Attachment K2-20

Excerpts from the Chevron Refinery Modernization Project Environmental Impact Report, State Clearinghouse No. 2011062042
Lead Agency: City of Richmond, CA

Excerpts included:

Appendix 4.3-URM: Unit Rate Model

Six Element Test Reports; quarterly reports, 2009 data.

APPENDIX 4.3 - URM

URM: Unit Rate Model

February 26, 2014

Ms. Shari Libicki
Environ
201 California St. #1280
San Francisco, CA 94111

Re: EIR for the Chevron Richmond Refinery Revised Renewal Project - Unit Rate Model Development and Use

Dear Shari:

Turner, Mason & Co. was engaged by Environ to provide refinery technical expertise to the City of Richmond for the development of an environmental impact report (EIR) for the Chevron Richmond Revised Renewal Project. The major changes in the refinery associated with the project include:

1. Construction of a new hydrogen plant to replace the existing plant (approximately 244 mmscf/d replacing a nominal 170 mmscf/d),
2. Increase the capacity of the FCC FHT from 65,000 b/d to 80,000 b/d, and
3. Increase the capacity of the sulfur recovery units from a nominal 600 long tons per day (lt/d) to 900 lt/d.

In addition to other tasks, TM&C was asked to develop a refinery unit rate model (URM) to 1) determine process unit rates in the refinery related to the use of different crude oil input blends, as well as, 2) expected sulfur recovery rates based on the sulfur content of crude and gas oil used by the refinery, and 3) the hydrogen production that the refinery would use from the proposed new hydrogen plant. TM&C was also asked to conduct several URM runs that included a range of potential crude oil blend inputs, and crude and gas oil sulfur contents, under pre- and post- Modernization Project conditions. TM&C developed the URM and conducted several URM runs over the period 2011-2014. The primary sources used to develop the model include:

Chevron Transmittal # 1, Revision #1
Chevron Transmittal #3C Rev. #2
Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) page 10.27 and page 14.36.
M. D. Edgar, A. D. Johnson, J. T. Pistorius and T. Varadi, “Troubleshooting on Hydrotreating Units,” National Petroleum Refiners Association Meeting, paper no. AM-84-38, page 7 (1984).

The technical report describing the URM, and several pre- and post- Modernization Project URM runs, is attached to this letter. The report accurately describes the URM, and accurately summarizes the URM results TM&C obtained for each of the scenarios in the report.

Sincerely,

Tom Hogan

Thomas R. Hogan
Senior Vice President
Turner, Mason & Co

APPENDIX 4.3
URM: UNIT RATE MODEL TECHNICAL APPENDIX

4.1 OVERVIEW

This technical appendix describes the unit rate model (URM) that was developed to estimate how the Chevron Richmond Refinery's (Facility's) processing units could potentially be used under post-Modernization Project conditions. The URM generates estimates of the daily average throughput or production of various Facility process units in relation to: (a) the amount of crude and gas oil inputs into the Facility; (b) the API gravity and fractional characteristics[1] of the crude oil inputs; and (c) the sulfur content of the crude and gas oil inputs.

Information used in the model was derived from the Facility's average daily operational activity and crude and gas oil inputs for the 3-year period 2008-2010 (the "Baseline Period"). The Baseline Period data was utilized to estimate how crude oil fractions and externally sourced, or purchased, gas oil would be allocated to specific process units. Applicable process unit throughputs were adjusted in the URM to reflect proposed post-Modernization Project permit limits, including a reduction in the permitted throughput limit of the Facility's solvent de-asphalting (SDA) unit to an annual average of 50,000 barrels per day (b/d).

The URM was designed to determine the volume of gas oil purchased by the Facility based on: (a) the amount of gas oil obtained from the crude oil blend used by the Facility; and (b) the percentage of total permitted gas oil capacity used by the five units that can initially process purchased gas oil in the Facility (the "gas oil gateway units"). As discussed below, the air quality analysis in the EIR considers URM cases that maximize total crude and gas oil use assuming that the crude and gas oil gateway units operate at 100% and 93% of post-Modernization Project permitted capacity.[2] The Facility did not operate at 100%

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[1] As discussed in Chapter 4.0 of this EIR, crude oil is input to the Facility and distilled in the crude unit into specific fractions of oil defined by boiling temperatures. The phrase "fractional characteristics" refers to the relative proportion of each fraction in the crude oil that enters the Facility crude unit.

[2] A 93% utilization rate is used in the Modernization Project EIR based on annual refinery utilization data for the western Unites States (Petroleum Administration Defense District Region V, or "PADD V") by the U.S. Energy Information Administration (EIA). Annual average PADD V refinery utilization rates are available for 1985-2012 (http://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_a.htm, accessed February 17, 2014) and averaged approximately 86.7% per year over this period. The highest annual average

or 93% of existing capacity during the entire Baseline Period, and for a variety of reasons refineries typically do not, or are not able to continuously operate at full capacity for annual durations. As a result, the URM results based on 100% and 93% crude unit and gas oil gateway unit capacity utilization provide a conservative estimate of the extent to which the Facility could be operated under post-Modernization Project conditions.

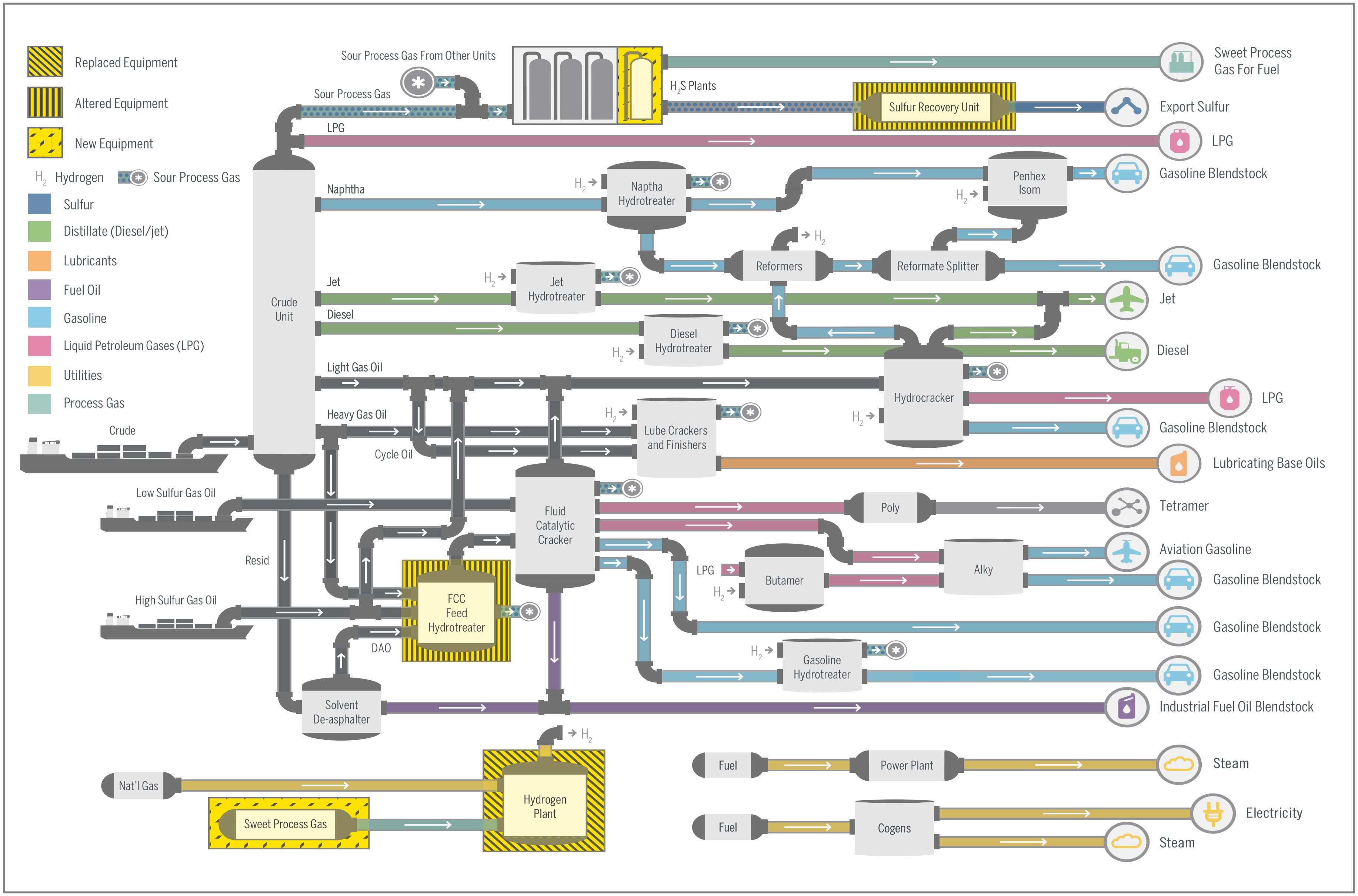
Table A4.3-URM-1 lists the Facility process units analyzed in the URM. Figure A4.3-URM-1 graphically depicts the relationship between the processing units analyzed in the URM.

TABLE A4.3-URM-1 FACILITY OPERATING UNITS INCLUDED IN THE URM

Crude Unit – Atmospheric Column	Polymerization Unit (Poly)
Crude Unit – Vacuum Column	Hydrocracker
Naphtha Hydrotreater (NHT)	Richmond Lube Oil Plant (RLOP)
Catalytic Reformers	LNC--light neutral hydrocracker
Pen/Hex Isomerization Unit (Pen/Hex)	LNF-light neutral hydrofinisher
Jet Hydrotreater (JHT)	HNC--heavy neutral hydrocracker
Diesel Hydrotreater (DHT)	HNF--heavy neutral hydrofinisher
Fluidized Catalytic Cracker Feed Hydrotreater (FCC FHT)	Solvent De-Asphalting (SDA) Unit
Fluid Catalytic Cracker (FCC) Unit	Sulfur Recovery Unit (SRU)
Gasoline Hydrotreater (GHT)	Hydrogen Plant
Alkylation Unit	

As shown in Figure A4.3-URM-1, gas oil obtained from the crude unit, and high- and low-sulfur gas oil purchased by and shipped to the Facility, is initially processed by one of five gas oil gateway units: the fluidized catalytic cracker feed hydrotreater (FCC FHT); the fluid catalytic cracker (FCC); the hydrocracker; and the light neutral hydrocracker (LNC) and heavy neutral hydrocracker (HNC) in

utilization rate was approximately 92.7% in 1998. To provide a conservative assessment, the EIR includes the analysis of 93% utilization cases to reflect the highest PADD V annual average refinery utilization rate reported by the EIA over 1985-2012.



02.28.2014 P:\11-005 CVRN\PRODUCTS\DEIR\Figures\Appx 4.3_AQ\AQ-URM Draft\CVRN Figure A4.3-URM-1

Source: Chevron (T39r2)

Figure A4.3-URM-1
Chevron Refinery Modernization Project EIR
General Facility Unit Flow Chart

the Richmond Lube Oil Plant (RLOP), which is a part of the Facility that produces lubricating oils. The percentage of total gas oil gateway unit permitted capacity that is utilized under future conditions is an input to the URM in each case. The model determines how much of the applicable gas oil gateway unit capacity will be supplied from the crude oil blend used by the Facility, and calculates how much additional gas oil must be purchased to achieve the specified utilization rate. In a 100% scenario, for example, the URM calculates the amount of gas oil the Facility would need to purchase, in addition to gas oil obtained from the applicable crude oil blend, to operate the gas oil gateway units at 100% of permitted capacity.

Several units, primarily the Facility hydrocrackers and hydrotreaters, use hydrogen to assist in the cracking process and remove sulfur in the form of hydrogen sulfide gas. These units are supplied with hydrogen produced by the Facility's catalytic reformers and the hydrogen plant, as well as hydrogen recovered from Facility process gas. The hydrogen sulfide gas created as a result of sulfur removal is separated from the hydrocarbon stream, conveyed to the sulfur recovery unit (SRU) and is recovered as elemental sulfur. The recovered sulfur is sold as "sulfur product" for agricultural and other uses.

The URM calculates SRU use rates under post-Modernization Project conditions as a function of the sulfur load into the refinery less the sulfur contained in the fuel oil blendstock that exits the Facility from the SDA. To provide a conservative assessment of emissions related to hydrogen production for extracting sulfur from various units, the URM assumes that all of the net sulfur load (crude blend sulfur minus the sulfur that exits the Facility as fuel oil blendstock from the SDA) to the Facility will be processed and recovered by the SRU, although very small amounts of sulfur exit the Facility as sulfur dioxide, due to the combustion of small amounts of sulfur in the Facility fuel gas, or in finished products. The heavy bottom discharge from the FCC unit also contains sulfur that is not further processed in the Facility or recovered by the SRU, but represents a small amount of the total sulfur input as well.

The URM was utilized to calculate Facility process unit throughput, sulfur recovery and hydrogen plant production levels under post-Modernization Project conditions using a representative selection of crude data to understand the effect of processing a range of heavier and lighter crude oil blends, higher or lower crude and gas oil sulfur contents, and greater or lower purchased crude and gas oil volumes. To provide a conservative assessment, while the crude blends analyzed in the "Modernization Project Related Cases" (see *Section 4.3.1.A*) are meant to be representative of crude blends that could be processed under post-Modernization Project operating conditions, the crude blends for these and other URM cases were generally considered without regard to feasibility due to factors such as accessibility, fractional properties that are incompatible with the range of crudes that the Facility is designed to process, or chemical properties, such as excessive acidity that would damage certain Facility processing units (see *Chapter 4.13, Public Safety*).

As discussed below, the Modernization Project EIR focuses on eight representative cases derived from the URM, including: (a) four cases based on 100% crude and gas oil gateway unit capacity utilization (100% Utilization scenarios); and (b) four cases based on 93% crude and gas oil gateway unit capacity utilization (93% Utilization scenarios). This URM appendix also discusses (a) three cases that illustrate model results based on Facility use of extremely light, extremely heavy and very high sulfur content crude oil; (b) two no-Modernization Project cases considered in the alternatives sections of the EIR assuming the Facility operates at 93% and 100% of the crude and gas oil gateway unit capacity without Modernization Project changes and using the average daily crude oil blends and gas oils from the Baseline Period; and (c) two "limited sulfur capacity" cases considered in the alternatives sections of the EIR assuming the Facility operates at 93% and 100% of the crude and gas oil gateway unit capacity under post-Modernization Project conditions but with a lower SRU capacity of 750 long tons per day (lt/d). For informational purposes, several other URM analysis results that were considered during the preparation of the Modernization Project EIR are included in Attachment 3.

4.2 URM METHODOLOGY

This section discusses the principal URM analysis methods for evaluating the post-Modernization Project process unit throughput rates related to processing heavier or lighter crude oil, crude or gas oil with higher or lower sulfur contents and different crude and gas oil capacity utilization levels, including: (1) the approach used to develop the URM from Baseline Period operational data; and (2) the methodologies used to estimate the volume of crude and gas oil use, sulfur removal and production, and hydrogen demand and production by the Facility under post-Modernization Project conditions.

4.2.1 Unit Rate Model Development

As illustrated in Figure A4.3-URM-1, crude oil blends enter the Facility through the crude unit and are distilled by heating into various fractions. These fractions are then fed to other process units within the Facility. The amount of each fraction is determined by the crude oil feedstock blend that enters the crude unit. Crude and gas oil feedstocks also contain varying amounts of sulfur that must be processed and removed from the Facility's products. Sulfur removal requires the use of hydrogen gas produced by other Facility operations and the hydrogen plant. The URM was developed to analyze how crude blend feedstocks with different fractional characteristics, and crude and gas oil feedstocks with different sulfur contents, would affect each unit's throughput volume. The results were utilized to calculate processing volume-related emissions considering a variety of potential future crude blend and gas oil use scenarios.

The URM was developed by using publicly available technical resources and historical, average daily Facility crude and gas oil use and process unit throughputs provided by the Modernization Project applicant for 2008-2010 (the “Baseline Period”), including the average crude oil blend fractional characteristics and the sulfur content of the Facility feedstocks. Table A4.3-URM-2 summarizes the fractional characteristics and sulfur content of the average crude oil blend and the sulfur content of the purchased gas oil (gas oil shipped to the refinery to supplement gas oil obtained from the crude oil feedstock) during the Baseline Period.

TABLE A4.3-URM-2 BASELINE PERIOD CRUDE OIL BLEND CHARACTERISTICS AND CRUDE AND GAS OIL SULFUR CONTENT

Fraction (Boiling Point, °F)	Volume of Crude Supply (%)
Crude Oil Fractional Characteristics	
Butane and Lighter Fractions	2.21
Naphtha (55-290)	19.29
Kerosene (290-510)	22.12
Diesel (510-625)	11.16
Gas Oil (625-770)	12.99
Heavy Gas Oil (770-1020)	17.25
Residuum (1020+)	14.99
Weight and Sulfur Content	
Crude Oil API Gravity (degrees)	33.7
Crude Oil Specific Gravity	0.857
Crude Oil Sulfur Content (wt. %)	1.58%
Sour Gas Oil Sulfur Content (wt. %)	1.5%
Sweet Gas Oil Sulfur Content (wt. %)	0.3%

As shown in Table A4.3-URM-2, during the Baseline Period, the Facility generally processed crude oil blends with an average gravity in the light end of the intermediate range and with an average API gravity of approximately 33.7

degrees (º). The crude oil sulfur content by weight during the Baseline Period was approximately 1.58% by weight.[3] The Facility also purchased "sweet" gas oil with an approximate sulfur content by weight of 0.25% for FCC unit processing, and "sour" gas oil with an approximate sulfur content by weight of 1.5% for processing by other gas oil units (see Table A4.3-URM-1 for process unit acronym definitions).

The crude oil fractional characteristics, gravity[4] and sulfur content data summarized in Table A4.3-URM-2 are inputs required by the URM to complete the analysis of each case and are derived from applicable crude oil assay data. These and other URM inputs are listed in Attachment 1 and include: (1) the crude oil blend fractional characteristics (percent of each fraction in the crude oil blend); (2) the crude oil blend sulfur content by percent weight: (3) the crude oil blend specific gravity; (4) the amount of total crude oil sulfur contained in the residuum and processed in the SDA; and (5) gas oil sulfur content by percent weight. These inputs will vary with different crude oil blends and gas oils that may be purchased for the Facility. As discussed below, the URM also uses the specific gravity of gas oil as an input to calculate the amount of sulfur recovered by the SRU, but this value is assumed to be 0.91.[5]

Table A4.3-URM-3 summarizes the average daily volume of crude and gas oil and unit throughput rates for the Facility during the Baseline Period and compares these rates to the applicable unit annual average permit limit under Title V of the federal Clean Air Act. During the Baseline Period, the Facility used approximately 227,900 b/d of crude oil and approximately 45,400 b/d of gas oil, including 34,500 b/d of "sweet" gas oil. Total crude and gas oil inputs were approximately 273,300 b/d. On an average daily basis, none of the Facility units included in the URM operated at applicable permitted limits during the Baseline Period.

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[3] All references to sulfur content in this technical appendix are expressed in terms of percent sulfur by weight.

[4] The API and specific gravity of a crude oil are different methods for expressing the same measure of weight or crude oil gravity. For calculation purposes, the URM uses the applicable specific gravity. For ease of reference, crude oil weights are generally described in terms of °API in the text of this appendix.

[5] The Modernization Project applicant has indicated that the gas oil purchased typically ranges from 22-36 °API. A specific gravity of 0.91 (24 °API) is near the lower end (heavier) of the API range and therefore provides a conservative estimate of the gas oil specific gravity used in the Facility.

TABLE A4.3-URM-3 BASELINE PERIOD FACILITY AVERAGE DAILY OPERATIONS

Oil Source	Input Rate (b/d)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
Crude and Gas Oil Inputs			
Crude Oil	227,900	257,200	88.6%
Sweet Gas Oil	34,500	N/A	
Sour Gas Oil	10,900	N/A	
TOTAL	**273,300**		

Operating Unit	Use Rate (b/d Except Where Noted)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
Process Unit Throughput/Production Rates			
Crude Unit – Atmospheric Column	227,900	257,200	88.6%
Crude Unit – Vacuum Column[a]	89,900	N/A	
NHT	49,800	57,600	86.5%
Catalytic Reformers	45,500	68,700	66.2%
Pen/Hex Isomerization Unit	24,600	65,000	37.8%
Butane Isomerization (Butamer) Unit[b]		12,000	
JHT	61,100	96,000	63.6%
DHT	28,800	64,800	44.4%
FCC FHT	36,300	65,000	55.8%
FCC	70,500	80,000	88.1%
GHT	17,200	64,800	26.5%
Alkylation Unit	27,700	36,000	76.9%
Polymerization Unit	6,700	8,000	83.8%
Hydrocracker	45,000	51,300	87.7%
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	12,600	16,500	76.4%

TABLE A4.3-URM-3 BASELINE PERIOD FACILITY AVERAGE DAILY OPERATIONS

Oil Source	Input Rate (b/d)	Existing (pre-Modernization Project) Annual Average Daily Limit (b/d)	Percent Existing Permit Limit Utilized
LNF – light neutral hydrofinisher	15,400	22,000	70.0%
HNC – heavy neutral hydrocracker	20,600	26,000	79.2%
HNF – heavy neutral hydrofinisher	6,000	12,000	50.0%
Solvent De-Asphalting (SDA) Unit	33,900	56,000	67.8%
Sulfur Recovery Unit (SRU)(long tons/day)	398	600	66.3%
Hydrogen Plant production (mmscfd)	164	181.1[c]	90.6%

Note: b/d = barrels per day; mmscfd= million standard cubic feet per day.

[a] The Baseline Period throughput level for the crude unit - vacuum column is a URM model estimate based on the average crude oil blend assay data and total feed to the crude unit.

[b] The butane isomerization (butamer) unit does not have an associated furnace and does not generate combustion-related emissions. As discussed below, the unit has been included in the analysis of hydrogen demand and does not otherwise affect the URM. The butamer unit permit limit is included for informational purposes in Table A4.3-URM-4.

[c] The permit limit for the existing hydrogen plant is not adjusted for purity. Existing hydrogen plant production is approximately 94% hydrogen. As a result, the actual amount of hydrogen available for Facility use at the existing plant's full capacity is approximately 170.2 mmscfd.

Based on the Baseline Period data provided by the Modernization Project applicant and other technical sources, the URM allocates crude and gas oil feedstocks to the Facility process units using the parameters listed in Attachment 2. The URM also incorporates the increased throughput limits for the FCC FHT, the new hydrogen plant and the SRU, and the 50,000 b/d limit on the SDA throughput, that would result from the proposed Modernization Project. These throughput limit changes are listed in Table A4.3-URM-4.

4.2.2 Crude Unit Capacity Utilization

The Facility is permitted to process up to 257,200 b/d of crude oil and this limit would not be modified by the Modernization Project. The percentage of the crude unit's capacity that is used in each case is specified as an input to the URM (see Attachment 1). A 93% utilization scenario, for example, analyzes Facility unit throughput volumes that result from using 93% of the crude unit's permitted capacity, or approximately 239,200 b/d.

TABLE A4.3-URM-4 EXISTING AND POST-PROJECT UNIT THROUGHPUT PERMIT LIMITS (CHANGES IN BOLD)

Process Unit (b/d except where noted)	Existing Permit Limit	Post-Modernization Project Permit Limit	Post-Modernization Project Change
Crude Unit – Atmospheric Column	257,200	257,200	0
Crude Unit Vacuum Column[a]	n/a	n/a	n/a
NHT	57,600	57,600	0
Catalytic Reformers	68,700	68,700	0
Pen/Hex Unit	65,000	65,000	0
Butane Isomerization Unit (Butamer)	12,000	12,000	0
JHT	96,000	96,000	0
DHT	64,800	64,800	0
FCC FHT	65,000	80,000	**15,000**
FCC	80,000	80,000	0
GHT	64,800	64,800	0
Alkylation Unit	36,000	36,000	0
Polymerization Unit	8,000	8,000	0
Hydrocracker	51,300	51,300	0
Richmond Lube Oil Plant (RLOP)			
LNC--light neutral hydrocracker	16,500	16,500	0
LNF-light neutral hydrofinisher	22,000	22,000	0
HNC--heavy neutral hydrocracker	26,000	26,000	0
HNF--heavy neutral hydrofinisher	12,000	12,000	0
SDA Unit	56,000	50,000	**-6,000**
SRU Plant (lt/d)	600	900	**300**
Hydrogen Plant production (mmscfd)	181.1[b]	244	**63**

Note: b/d = barrels per day; mmscfd= million standard cubic feet per day; lt/d = long tons per day.

[a] The Crude Unit's vacuum column only receives feed directly from the crude unit's atmospheric column.

[b] The permit limit for the existing hydrogen plant is not adjusted for purity. Existing hydrogen plant production is approximately 94% hydrogen. As a result, the actual amount of hydrogen available for Facility use at the existing plant's full capacity is approximately 170.2 mmscfd.

The Facility's ability to process crude oil that is much heavier or lighter than the crude oil blend used during the Baseline Period is subject to two existing constraints that would not be affected by the Modernization Project: (1) the SDA throughput limit for heavier crude oils, and (2) the NHT throughput limit for lighter crude oils.

In general, heavier crude oil contains a proportionately larger share of heavier fractions, including the heaviest fraction, the residuum. The entire residuum fraction in the crude blend feedstock to the Facility is routed from the crude unit to the SDA unit for further processing. In the SDA unit, the residuum is separated into either de-asphalted oil (DAO), which is then routed to other Facility units, or fuel oil blendstock, which exits the Facility from the SDA. The SDA annual average throughput limit under existing permits is 56,000 b/d, but equipment limitations and other factors do not allow the unit to operate at more than an annual average throughput of 50,000 b/d. The Facility is not equipped with alternative process units or sufficient storage and treatment facilities to manage the residuum other than by routing this fraction to the SDA unit. The Modernization Project will not add any additional residuum processing or storage capacity to the Facility, and the Facility will commit to limiting SDA throughput by permit to 50,000 b/d on an annual average basis as a result of the Modernization Project. Consequently, under post-Modernization Project conditions, the Facility will be unable to process crude oil blends up to the permitted maximum of 257,200 b/d that contain more than 50,000 b/d of residuum on an annual average basis.

The Facility's ability to process much lighter crude blends than during the Baseline Period is constrained by the NHT throughput permit limit of 57,600 b/d. The NHT processes all of the naphtha fraction separated by the crude unit and receives additional feed from other Facility process units (see Attachment 2). The Facility is not equipped with alternative process units or sufficient storage and treatment facilities to process or store naphtha other than by routing these fractions to the NHT. The Modernization Project will not add any additional naphtha processing or storage capacity to the Facility, and the existing NHT throughput limit will not be modified by the Modernization Project. Consequently, under post-Modernization Project conditions, the Facility will be unable to process crude oil blends up to the permitted maximum of 257,200 b/d that, in combination with naphtha from other Facility units, would exceed 57,600 b/d of naphtha.

Table A4.3-URM-5 illustrates how the volume of heavier and lighter crudes could be constrained by the SDA and NHT unit throughput limits. Heavier crudes (e.g., Eocene crude with an approximate API of 18.3º) can contain more residuum than can be processed by the SDA at maximum crude rates. Eocene crude assay data, for example, indicates that 37.2% of the crude oil consists of residuum. The

Facility would be unable to process more than approximately 135,000 b/d of this crude oil blend without exceeding the SDA unit's 50,000 b/d limit.

Lighter crudes, (e.g., 100% Bakken crude with an approximate API of 41º) that contain a significantly higher amount of the naphtha fraction would, in combination with feeds routed from other Facility units, also be processed through the crude unit at a lower rate than the permitted limit. As illustrated in Table A4.3-URM-5, 100% Bakken crude assay data indicates that approximately 25% of the crude oil consists of the naphtha fraction. Feed from other Facility units also accounts for a portion of the NHT throughput. The Facility would be unable to process more than approximately 199,300 b/d of Bakken crude oil without exceeding the NHT unit's 57,600 b/d capacity.

In summary, to provide a conservative assessment, the URM is designed to use as much crude oil as possible up to the level of the crude unit's capacity utilization that is input to the model. The model can be iteratively run to identify crude oil blends that can be used by the Facility up to the 50,000 b/d SDA, the 57,600 b/d NHT, or any other unit's permit limit that might be exceeded before the specified level of crude unit capacity could be fully utilized.

4.2.3 Gas Oil Capacity Utilization

As discussed in *Chapter 4.0* of this EIR, gas oil is separated from crude oil by the crude unit and DOA is separated from the residuum by the SDA unit. There are no permit limits on the amount of gas oil that can be purchased for Facility use, and the total volume of gas oil utilization is limited by the capacity of the gas oil gateway units. Throughput limits for four gas oil gateway units—the FCC, the hydrocracker; the LNC and the HNC—would not be modified by the Modernization Project. The Modernization Project would increase the permitted throughput limit of the FCC FHT, the fifth gas oil gateway unit, by 15,000 b/d, which would increase the Facility's total gas oil processing capacity by approximately 1,200 b/d (see EIR *Chapter 3.0, Project Description, Section 3.3.2.1*). The URM accounts for the gas oil processing capacity increases that would result from the Modernization Project under future conditions.

The percentage of the gateway gas oil units' capacity that is used in each case is specified as an input to the URM (see Attachment 1). A 93% Utilization scenario, for example, analyzes Facility unit throughput volumes that result from using 93% of the crude unit and the gas oil gateway unit capacities. The amount of gas oil purchased for Facility use is calculated in the following manner:

1. Calculate the amount of gas oil required to operate the gas oil gateway units under post-Modernization Project conditions at the specified utilization level (e.g., 93%, 100% etc.);

TABLE A4.3-URM-5 ILLUSTRATION OF POTENTIAL CRUDE OIL USE CONSTRAINTS

Fraction Name and Boiling Point (°F)	Percent of Crude Supply	Volume of Each Fraction (b/d, rounded to nearest 100)	Does the volume of a crude oil fraction result in a Facility feed that exceeds a processing unit throughput permit limit?
Baseline Period Crude Oil Blend (API = 33.7°)			
Butane and Lighter Fractions	2.21	5,700	NO
Naphtha (55-290)	19.29	49,600	NO
Kerosene (290-510)	22.12	56,900	NO
Diesel (510-625)	11.16	28,700	NO
Gas Oil (625-770)	12.99	33,400	NO
Heavy Gas Oil (770-1020)	17.25	44,400	NO
Residuum (1020+)	14.99	38,600	NO
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*257,200*	
Heavier Crude Oil (e.g., Eocene crude, API = 18.3°)			
Butane and Lighter Fractions	0.67	900	NO
Naphtha (55-290)	7.07	9,500	NO
Kerosene (290-510)	12.72	17,200	NO
Diesel (510-625)	9.24	12,500	NO
Gas Oil (625-770)	12.30	16,600	NO
Heavy Gas Oil (770-1020)	20.98	28,300	NO
Residuum (1020+)	37.02	50,000	**YES: SDA**
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*135,000*	
Light Crude Oil (e.g., 100% Bakken, API = 41°)			
Butane and Lighter Fractions	2.87	5,700	NO
Naphtha	25.20	50,200[a]	**YES: NHT[a]**
Kerosene (290-510)	26.54	52,900	NO
Diesel (510-625)	11.61	23,100	NO
Gas Oil (625-770)	11.82	23,600	NO

TABLE A4.3-URM-5 ILLUSTRATION OF POTENTIAL CRUDE OIL USE CONSTRAINTS

Fraction Name and Boiling Point (°F)	Percent of Crude Supply	Volume of Each Fraction (b/d, rounded to nearest 100)	Does the volume of a crude oil fraction result in a Facility feed that exceeds a processing unit throughput permit limit?
Heavy Gas Oil (770-1020)	15.20	30,300	NO
Residuum (1020+)	6.77	13,500	NO
Volume Crude Oil Use Without Exceeding a Processing Unit Throughput Limit		*199,300*	

[a] The throughput total includes Facility feeds from other units as well as the naphtha fraction from the crude oil feedstock. If 100% Bakken crude with the fractional characteristics identified in Table A4.3-URM-5 was used by the Facility, the URM indicates that total NHT throughput from all feed sources would reach the 57,600 b/d NHT processing limit. The amount in the table is the naphtha feed from the crude unit alone not including feed from other Facility units.

2. Calculate the amount of gas oil supplied from crude oil based on the fractional characteristics of the crude oil blend used in the applicable scenario and the specified crude unit utilization (e.g., 93%, 100%, etc.);
3. Calculate the amount of gas oil that is an intermediate product of other internal Facility process units (e.g. hydrotreated gas oil from FCC FHT or DAO recovered from residuum by the SDA); and
4. Calculating the total maximum volume of purchased gas oil by subtracting (a) the amount of gas oil obtained from crude oil and from internal Facility processes from (b) the amount of gas oil required to operate the gas oil gateway units under post-Modernization Project conditions at the specified utilization level.

To provide a conservative assessment, the URM assumes that all of the purchased gas oil under post-Modernization Project conditions will consist of "sour" feedstock with higher sulfur content except for purchased gas oil routed directly to the FCC. To meet product sulfur content specifications, the FCC only processes low-sulfur, "sweet" gas oils. Based on the URM model parameters listed in Attachment 2, and to provide a conservative assessment of the amount of sulfur in purchased gas oil, the URM assumes that approximately 4,000 b/d of sweet gas oil will be purchased under post-Modernization Project conditions to operate both the FCC and the FCC FHT at full permitted capacity (the amount of sweet gas oil is scaled by the specified level of utilization in cases that assume less than 100% utilization). In comparison, the Facility purchased approximately 34,500 b/d of sweet gas oil during the Baseline Period.

The method by which the URM calculates gas oil imports is illustrated in Table A4.3-URM-6 for a scenario that assumes 100% of the gas oil gateway unit capacity is utilized and that the crude oil feedstock has the same fractional characteristics as during the Baseline Period (see Table A4.3-URM-3). Approximately 253,800 b/d of gas oil would be required to operate the gas oil gateway units at full capacity. Approximately 77,800 b/d of gas oil would be obtained from the crude oil feedstock, and 110,800 b/d would be produced by other Facility processing units. Crude oil and internal Facility processing would therefore generate a gas oil supply of 188,600 b/d. As a result, approximately 65,200 b/d of gas oil would be purchased to operate the gas oil gateway units at full capacity (253,800-188,600 b/d). The amount of gas oil purchased under post-Modernization Project conditions varies with (a) the fractional characteristics of the crude oil feedstock, (b) the percentage of the crude unit's total capacity use, and (c) the percentage of total gas oil gateway unit capacity use that are entered as inputs to the URM (see Attachment 1).

4.2.4 Sulfur Content and SRU Analysis

The Modernization Project would increase the Facility's sulfur recovery or sulfur production limit from approximately 600 lt/d[6] to 900 lt/d. The crude and gas oil used in the Facility contains sulfur that must be removed during the refining process. The URM assumes that all sulfur entering the Facility in crude or gas oil will exit the Facility either in the fuel oil blendstock produced by the SDA unit, or as elemental sulfur recovered by the SRU. This methodology maximizes the energy required to treat and remove sulfur.

For crude oil, the URM estimates the total sulfur content (by weight) in the crude oil purchased for the Facility, and the weight of the sulfur that will exit the Facility in the fuel oil blendstock produced by the SDA. To determine the amount of sulfur in the fuel oil blendstock, the URM estimates the amount of total crude oil sulfur contained in the residuum fraction processed in the SDA. The residuum sulfur content varies with the characteristics of each crude oil purchased for the Facility. The ratio of the sulfur contained in the residuum to the total amount of sulfur in the crude oil sulfur is entered as an input to the URM based on applicable assay data for each case (see Attachment 1). In general, the residuum contains from 20% to 60% of the total sulfur in the crude oil feedstock.

[6] A long ton is 2,240 pounds.

TABLE A4.3-URM-6 GAS OIL DEMAND

	Barrels per Day
Gas Oil Gateway Unit Capacity at 100% Utilization	
FCC FHT	80,000
FCC	80,000
Hydrocracker	51,300
LNC	16,500
HNC	26,000
Total Gas Oil Gateway Unit Demand at 100% of Capacity	*253,800*
Gas Oil Supply from Crude and Refining	
Gas Oil from Crude Unit	(77,800)
DAO from SDA	(27,800)
Gas Oil Feed from FCC FHT to FCC	(73,600)
Gas oil from HNC	(2,400)
Gas Oil from FCC to Hydrocracker	(4,000)
Recycled Gas Oil from FCC to FCC FHT	(3,000)
Total Gas Oil from Crude Imports and Facility Processing	*(188,600)*
Gas Oil Import Volume	
TOTAL	**65,200**
Low Sulfur (Sweet) Gas Oil (for FCC Operation)	*4,000*
High Sulfur (Sour) Gas Oil	*61,200*

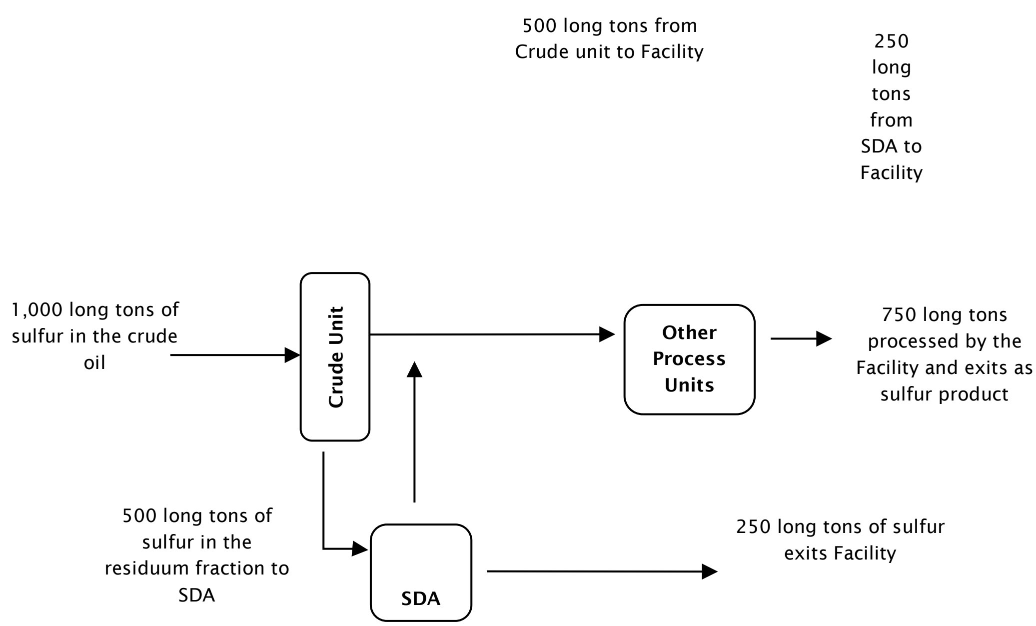
Note: Assuming (1) 100% gas oil unit and crude unit capacity use; and (2) crude oil with baseline period characteristics (see Table A4.3-URM-3) (barrels per day).

The URM then calculates the percentage of sulfur in the residuum that will exit the Facility in the fuel oil blendstock produced by the SDA and not further processed. Published information indicates that approximately 50% of the sulfur in the residuum will exit the Facility in the fuel oil blendstock,[7] and the URM utilizes this ratio assumption for all cases (see Attachment 2).

[7] Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) p 10.27.

Figure A4.3-URM-2 illustrates the relationships between the crude unit, the SDA, and the rest of the Facility assuming that the crude oil feedstock contains 1000 long tons of sulfur and 50% of the total sulfur in the crude oil is contained in the residuum fraction. Under these assumptions, the URM calculates that 50% of the sulfur in the import crude oil (500 long tons) is contained in the fractions sent directly from the crude unit to other process units. The remaining 50% of the sulfur (500 long tons) is contained in the residuum and processed in the SDA. Half of the residuum sulfur content (250 long tons) will exit the refinery in the form of fuel oil blendstock produced by the SDA, and half (250 long tons) will be included in the gas oil produced by the SDA and sent to other Facility units for further processing. The total amount of sulfur processed by the Facility (not including the sulfur in the fuel oil blendstock) is 750 long tons. The URM assumes that all of the 750 long tons will be recovered by the SRU and will exit the Facility as elemental sulfur or sulfur product.

FIGURE A4.3-URM-2 ILLUSTRATION OF FACILITY SULFUR LOAD FROM CRUDE OIL FEEDSTOCK (1,000 LONG TONS OF SULFUR IN CRUDE OIL; 50% OF CRUDE OIL SULFUR IN RESIDUUM)



For gas oil, the URM assumes that all of the sulfur in purchased gas oil will be further processed within the Facility and exit as sulfur product from the SRU. The sulfur load attributable to purchased gas oil is calculated by estimating the total sulfur content by weight in sweet and sour gas oil based on the purchased volumes calculated by the URM.

Tables AQ-URM-7 and AQ-URM-8 illustrate the URM sulfur calculation methodology using model inputs that assume: (a) the crude oil feedstock has an API of approximately 31° and a sulfur content by weight of 2.75%; (b) purchased gas oil has a sulfur content by weight of 2.66%; (c) based on assay data, 19.44% of the crude oil feedstock consists of residuum and 55% of the total crude oil sulfur is contained in the residuum; and (d) the crude and gas oil gateway units are operated at 100% of capacity. As shown in Table A4.3-URM-7, the URM calculates that the Facility could process 257,200 b/d of crude oil, the permit maximum, without exceeding the NHT or the SDA throughput limits. In addition, approximately 57,000 b/d of purchased gas oil would be required to operate the gas oil gateway units at full capacity.

The total amount of sulfur introduced into the Facility is calculated using the crude and gas oil feedstock volumes, applicable crude and gas oil specific gravity data, and the percentage of sulfur by weight for each feedstock. Using this information, the URM calculates that the crude oil would contain approximately 962 lt/d of sulfur and that 55% of this amount (540 lt/d) will be routed to and processed in the SDA. The URM assumes that 50% of the sulfur processed in the SDA (265 lt/d) will exit the Facility in the fuel oil blendstock produced by the SDA without further processing.[8] The remaining half of the sulfur in the SDA (265 lt/d) will be routed to other Facility process units in the gas oil produced by the SDA. As shown in Table A4.3-URM-8, the total amount of sulfur from crude oil processed in the Facility will be 698 lt/d (962-265 lt/d).

The amount of sulfur in the purchased gas oil is calculated by using the gas oil specific gravity factor (0.91) assumed in the URM (see Attachment 1) and the percentage of sulfur by weight in sour and sweet gas oil purchased by the Facility. Based on this information, the URM calculates that the purchased sour gas oil will contain approximately 201 lt/d, and the purchased sweet gas oil will contain about 1 lt/d, or a total of 202 lt/d. The total sulfur processed in the Facility from both purchased import crude and gas oil, less the sulfur in the fuel oil blendstock produced by the SDA, would be 900 lt/d (698 + 202 lt/d). Under these conditions, the SRU would operate at its full post-Modernization Project

[8] From Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) p 10.27.

TABLE A4.3-URM-7 ILLUSTRATION OF URM UNIT RATE CALCULATIONS

Unit	Unit Rate (b/d)
Crude Oil	257,200
Purchased Gas Oil	57,000
Sweet Gas Oil	*4,000*
Sour Gas Oil	*53,000*
Total	**314,200**
Process Unit	**Throughput Rate (b/d)**
Crude Unit – Atmospheric Column	257,200
Crude Unit – Vacuum Column	116,700
NHT	52,000
Catalytic Reformers	48,800
Pen/Hex Isomerization Unit	27,000
JHT	64,100
DHT	31,300
FCC FHT	80,000
FCC	80,000
GHT	19,500
Alkylation Unit	27,700
Polymerization Unit	7,600
Hydrocracker	51,300
Richmond Lube Oil Plant (RLOP)	
LNC – light neutral hydrocracker	16,500
LNF – light neutral hydrofinisher	22,000
HNC – heavy neutral hydrocracker	26,000
HNF – heavy neutral hydrofinisher	12,000
Solvent De-Asphalting (SDA) Unit	50,000

Notes: Except where noted; numbers are rounded to nearest 100.
Crude oil feedstock API = 31° and consists of 19.44% residuum. Crude and gas oil gateway units operating at 100% of capacity.
Table A4.3-URM-7 is based on Basrah/Arab Light crude blend.

TABLE A4.3-URM-8 ILLUSTRATION OF URM SULFUR CONTENT AND SRU ANALYSIS CRUDE AND GAS OIL GATEWAY UNITS OPERATING AT 100% OF CAPACITY

Crude Oil Sulfur Load	
Crude Oil Density, API Gravity	31.0
Crude Oil Specific Gravity	0.826
Crude Oil Sulfur Content by Weight	2.75%
Crude Oil Volume (b/d)	257,200
Total Sulfur in Crude (lt/day)	**962**
Sulfur Exiting Facility in Fuel Oil Blendstock from SDA (lt/day)	(265)
Percent Total Crude Sulfur by Weight in Residuum Processed in SDA	*55%*
Percent Sulfur Load Exiting Facility in Fuel Oil Blendstock from SDA	*50%*
Net Sulfur in Crude Oil Entering Facility excluding SDA Discharge (lt/day)	**698**
Gas Oil Sulfur Load	
Gas Oil (sweet and sour) Specific Gravity	0.91
"Sweet" Gas Oil Sulfur Content by Weight	0.25%
"Sweet" Gas Oil Volume (b/d)	4,000
"Sour" Gas Oil Sulfur Content by Weight	2.66%
"Sour" Gas Oil Volume (b/d)	53,000
Long tons per day Sulfur in Gas Oil	***202***
Total Sulfur in "Sweet" Gas Oil (lt/day)	*1*
Total Sulfur in "Sour" Gas Oil (lt/day)	*201*
Total Sulfur Processed by SRU in Facility (lt/day)	**900**

capacity and recover 900 lt/d from the Facility process units. The amount of sulfur the Facility processes varies with differences in the sulfur content, feedstock volumes, crude oil specific gravity, and the percentage of total crude oil sulfur contained in the residuum fraction for each case.

4.2.5 Post-Modernization Project Hydrogen Plant Production Calculation Methodology

Hydrogen is used within Facility process units for (a) the removal of sulfur and other naturally occurring impurities, and (b) “cracking” or otherwise changing crude oil fractions. As shown in Figure A4.3-URM-1, hydrogen is supplied to several units and is produced by the Facility during the catalytic reforming process. Hydrogen is also recovered from various process gas streams and produced by the hydrogen plant for Facility use. Table A4.3-URM-9 lists the Facility process units that use hydrogen, and the hydrogen producing and recovery Facility activities analyzed in the URM.

The URM calculates post-Modernization Project hydrogen plant production for Facility use by subtracting the amount of hydrogen obtained from the Facility's catalytic reformers and process gas recovery from the total Facility hydrogen demand. Total Facility hydrogen demand is calculated by: (a) calculating per-barrel hydrogen demand for each hydrogen-using process unit, assuming crude and purchased sour gas oil has the same sulfur content as during the Baseline Period; and (b) adjusting the hydrogen demand as necessary to reflect increases or decreases from Baseline Period crude and purchased sour gas oil sulfur levels. The amount of hydrogen supplied by the production plant for Facility use is the difference between total Facility hydrogen demand adjusted for applicable sulfur content levels, and the amount of hydrogen available from other Facility operations.

Table A4.3-URM-10 illustrates the URM hydrogen plant production calculation methodology using the same model inputs in Tables AQ-URM-7 and AQ-URM-8, including a crude oil feedstock sulfur content of 2.75% and a purchased sour gas oil sulfur content of 2.66%. A per-barrel hydrogen demand factor for each of the Facility process units that use hydrogen was derived technical sources and Baseline Period operational data and integrated into the URM. Under Baseline Period conditions, for example, the NHT was estimated to use approximately 95 standard cubic feet (scf) of hydrogen per barrel and approximately 5.3 million scf per day (mmscfd) of hydrogen at a daily throughput of 56,200 b/d. The hydrocracker was estimated to use approximately 2,150 scf of hydrogen per barrel and approximately 110.3 mmscfd at a daily throughput of 51,300 b/d (see Attachment 2 for the hydrogen demand factors estimated for applicable units in the URM).

The URM adjusts the Facility's hydrogen demand by calculating the difference between the percentage of sulfur by weight in the crude oil (net of the sulfur that exits the Facility in the SDA fuel oil blendstock) and purchased gas oil compared with Baseline Period levels. If the sour gas oil content in a certain case is 2.5%, for example, the difference between the Baseline Period gas oil sulfur content level of 1.5% is +1.0%. Based on available technical information, approximately 100 scf per barrel per day is required to change the sulfur content of a barrel of

TABLE A4.3-URM-9 LIST OF FACILITY UNITS THAT USE OR PRODUCE HYDROGEN

Refinery Units that Use Hydrogen	Refinery Operations that Produce or Recover Hydrogen
NHT	Catalytic Reformers[a]
JHT	Hydrogen Recovery from Process Gas
DHT	Hydrogen Plant – Hydrogen Production
FCC FHT	
Hydrocracker	
GHT	
Pen/Hex Isomerization Unit	
Richmond Lube Oil Plant (RLOP)	
LNC – light neutral hydrocracker	
LNF – light neutral hydrofinisher	
HNC – heavy neutral hydrocracker	
HNF – heavy neutral hydrofinisher	
Butamer Unit	

[a] The catalytic reformers use and produce hydrogen and are a net hydrogen producer. As a result, these units are included in the list of refinery operations that produce or recover hydrogen.

TABLE A4.3-URM-10 ILLUSTRATION OF URM HYDROGEN DEMAND ANALYSIS

	Barrels per Day[a]	Demand or Production (scf per Barrel)	Total H2 Demand or Production (mmscfd)
Hydrogen Demand			
NHT	52,000	95	4.9
JHT	64,000	145	9.3
DHT	31,300	425	13.3
FCC FHT	80,000	-	
Purchased gas oil+ vacuum gas oil	*41,000*	*630*	*25.8*
SDA-Produced DAO + recycled gas oil	*39,000*	*950*	*37.1*
Hydrocracker	51,300	2,150	110.3

TABLE A4.3-URM-10 ILLUSTRATION OF URM HYDROGEN DEMAND ANALYSIS

	Barrels per Day[a]	Demand or Production (scf per Barrel)	Total H2 Demand or Production (mmscfd)
GHT	19,500	60	1.2
Pen/Hex Isomerization and Benzene Saturation Unit	27,000	295	8.0
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	16,500	1,100	18.2
LNF – light neutral hydrofinisher	22,000	150	3.3
HNC – heavy neutral hydrocracker	26,000	1,100	28.6
HNF – heavy neutral hydrofinisher	12,000	250	3.0
Butamer Unit Use[b]		0.30	0.3
Sulfur Adjustment (100 SCF/Barrel per percent change from Baseline Period Sulfur Content)[c]			
Crude Oil Sulfur Content Adjustment (mmscfd)			*21.6*
Gas Oil Sulfur Content Adjustment (mmscfd)			*6.1*
Total Facility Hydrogen Demand			**291.0**
Hydrogen Supply From Refinery Operations			
Hydrogen Produced by the Catalytic Reformers	48,800	850	(41.5)
Hydrogen Recovered from Process Gas/Percent Recovery	34.18	90%	(30.8)
Total Hydrogen Supply from Operations			**(72.3)**
Total Hydrogen Plant Production for Facility Use			**218.8**

[a] See Table 7, rounded to nearest 100.
[b] The URM assumes that the butamer unit will have constant demand of 0.3 mmscfd.
[c] Adjustment factors from M.D. Edgar, et. al. 1984.

oil by 1% (M.D.Edgar, et. al., 1984).[9] As a result, the URM assumes that processing gas oil with a sulfur content of 2.5% would require 100 scf per barrel more hydrogen than gas oil with a Baseline Period sulfur content of 1.5%.

[9] The adjustment factor is consistent with estimates of theoretical hydrogen usage, that show the that the amount of hydrogen required to remove one incremental percent

Table A4.3-URM-11 illustrates the URM hydrogen demand adjustment summarized in Table A4.3-URM-10 in more detail. Excluding the sulfur exiting the Facility from the SDA, the sulfur content in the Baseline Period crude oil blend was 1.26% by weight. The sulfur content in the crude oil analyzed in Table A4.3-URM-11 is 2.15% excluding the sulfur exiting the Facility from the SDA, an increase of 0.89% from Baseline Period levels. Based on this differential, the URM increases total Facility hydrogen demand by 21.6 mmscfd given a total import crude volume of 238,714 b/d to the Facility excluding the volume of fuel oil blendstock discharged from the SDA. The sulfur content in Baseline Period sour gas oil was 1.5% compared to the value of 2.66% assumed in AQ-URM-Table 11. Based on this differential, the URM increases total Facility hydrogen demand by 6.1 mmscfd utilizing the calculated purchased sour gas oil volume of 53,000 b/d (see Table A4.3-URM-8).

Including these adjustments, the URM calculates that the total Facility hydrogen demand will be 291 mmscfd (see Table A4.3-URM-10).

The URM solves for the amount of hydrogen that the hydrogen plant supplies to the Facility by comparing total demand to internally-generated Facility hydrogen supplies. The Facility produces hydrogen from two internal sources: (a) the catalytic reformers at an assumed post-Modernization Project rate of approximately 850 scf per barrel of throughput; and (b) hydrogen recovered from process gas in the pressure swing absorption unit. Based on information supplied by the Modernization Project applicant, the hydrogen content available for recovery from process gas using Baseline Period crude and gas oil is approximately 30 mmscfd. The URM also assumes 90% of the fuel gas hydrogen will be recovered under post-Modernization Project conditions for use in the Facility.[10] Under the assumptions used in Tables AQ-URM-7 to AQ-URM-11, the

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of sulfur per barrel would be 34-40 scf. This range was calculated via the following equation:

$$H = SG_{crude} \times \rho_{water} \times 42\frac{gallons}{barrel} \times 1\%S \times \frac{1\ lb{-}mol}{32.07\ lb\ S} \times \frac{1\ lb{-}mol\ S}{1\ lb{-}mol\ H_2} \times \frac{1\ scf}{0.0026412\ lb{-}mol}$$

Where:

H = scf H_2/barrel/%Sulfur

SG_{crude} = Specific Gravity (ratio of a material's density to that of water) of crude oil; ranges from 0.8203-0.97 for crudes considered in this EIR (unitless)

ρ_{water} = density of water (8.3 lbs/gallon)

This assumes that it would take exactly one mole of hydrogen to remove one mole of sulfur. However, the hydrogen gas can be consumed in other chemical reactions, or simply may not react at all, requiring a greater amount of hydrogen than under ideal calculations.

[10] The URM estimates the fuel gas hydrogen content by multiplying the per unit hydrogen demand prior to adjustment by 13%. This produces 30 mmscfd under post-

TABLE A4.3-URM-11 ILLUSTRATION OF FACILITY HYDROGEN DEMAND ADJUSTMENT

Crude Oil Hydrogen Demand Adjustment	
Sulfur in Crude Oil Excluding Fuel Oil Blendstock Produced by the SDA	2.15%
Baseline Period Sulfur in Crude Oil Net of SDA Fuel Oil Blendstock	1.26%
Difference from Baseline Period	0.89%
Hydrogen Demand Per Barrel Per Percent Sulfur Content by Weight (SCF)	100
Crude Oil Excluding the Fuel Oil Blendstock Produced by the SDA (b/d)	238,714
Crude Oil Sulfur Content Adjustment (mmscfd)	**21.6**
Gas Oil Hydrogen Demand Adjustment	
Sulfur in Sour Gas Oil	2.66%
Baseline Period Sour Gas Oil Sulfur Content	1.50%
Difference from Baseline Period	1.16%
Hydrogen Demand Per Barrel Per Percent Sulfur Content by Weight (SCF)	100
Sour Gas Oil (b/d)	53,000
Gas Oil Sulfur Content Adjustment (mmscfd)	**6.1**

reformers and process gas recovery process would generate 72.2 mmscfd of hydrogen for Facility use compared with a Facility demand of 291 mmscfd. The URM calculates the difference between the available internal Facility hydrogen supply and total Facility demand, or 218.8 mmscf (291-72.2 mmscf) and assumes that all of the difference in demand will be met by hydrogen supplied from the hydrogen plant. The total amount of hydrogen used in the Facility, and the hydrogen plant's level of production, will vary with the level of crude and gas oil sulfur content, crude and purchased gas oil feedstock volumes, the amount of sulfur in the fuel oil blendstock produced by the SDA that exits the Facility, and crude oil specific gravity applicable to each case.

Modernization Project, maximum use conditions assuming crude and purchased gas oil with the same characteristics as during the Baseline Period. The available hydrogen in fuel gas will vary with calculated unit throughputs and is scaled in all cases by the 13% factor derived from Baseline period data. As shown in Table 9, when applicable unit throughput rates are higher than the results obtained from using Baseline Period crude and gas oil, the amount of hydrogen recovered from fuel gas can be slightly higher (i.e., 34.18 mmscf) than 30 mmscf.

4.2.6 2011 Facility Data and URM Analysis Results

This section compares the URM gas oil purchase, unit rate, and sulfur and hydrogen production calculations with actual refinery operations in 2011. The Notice of Preparation for the Modernization Project was issued in 2011, and the prior 3 years of operational information was used to evaluate the Facility's existing annualized operations. After the URM was developed, one more year of annualized operational data became available for 2011.[11] The actual 2011 Facility operating data was compared with model calculations using 2011 inputs to evaluate the accuracy of the URM. As discussed above, the URM requires certain inputs to calculate unit rates, sulfur recovery by the SRU, hydrogen demand and total crude and purchased gas oil use. Table A4.3-URM-12 summarizes the URM crude oil inputs from 2011 operational data provided by the Modernization Project applicant.

TABLE A4.3-URM-12 2011 CRUDE OIL VOLUME, WEIGHT AND FRACTIONAL DATA INPUT TO THE URM

Crude Oil Utilization (b/d)	195,600
Crude Oil API Gravity (degrees)	34
Specific Gravity	0.855
Fraction (Boiling Point, ºF)	**Percent of Total Crude Oil**
Butane and Lighter Fractions	2.09
Naphtha (55-290)	19.11
Kerosene (290-510)	22.46
Diesel (510-625)	11.30
Gas Oil (625-770)	13.17
Heavy Oil (770-1020)	17.37
Residuum (1020+)	14.51

The refinery utilized approximately 195,600 b/d of crude oil during 2011 with gravity of approximately 34º API. The fractional characteristics of the 2011 crude oil feedstock were estimated on the basis of applicable assay data.

[11] The Facility crude unit was not operated for portions of 2012 and 2013 due to a fire in August 2012. As a result, 2012 and 2013 do not reflect the Facility's typical annualized operations.

Table A4.3-URM-13 summarizes the sulfur content inputs for 2011 entered into the URM.

TABLE A4.3-URM-13 2011 SULFUR CONTENT DATA INPUT TO THE URM

Crude Oil Sulfur Content	1.50%
Sour Gas Oil Sulfur Content	1.50%
Sweet Gas Oil Sulfur Content	0.25%
Crude Oil Sulfur in Residuum Fraction Processed in SDA	50%

Based on crude oil blend summaries provided by the Modernization Project applicant, the sulfur content of the crude oil was estimated to be approximately 1.50% by weight in 2011. The sulfur content in 2011 gas oil purchased by the Facility was estimated on the basis of consultations with the Modernization Project applicant and was approximately 0.25% by weight for sweet gas oil and approximately 1.50% by weight for sour gas oil. Based on assay data, approximately 50% of the crude oil sulfur content was contained in the residuum processed by the SDA during 2011, approximately the same ratio as the Baseline Period.

Table A4.3-URM-14 summarizes the gas oil gateway unit utilization rates for 2011 that were input to the URM.

TABLE A4.3-URM-14 2011 GAS OIL GATEWAY UNIT THROUGHPUT DATA INPUT TO THE URM

Gas Oil Gateway Unit	2011 Utilization (b/d)	Percent of 2011 Permitted Capacity
FCC FHT	33,800	52%
Hydrocracker	44,500	87%
FCC	70,400	88%
RLOP Hydrocrackers		
LNC – light neutral hydrocracker	10,200	62%
HNC – heavy neutral hydrocracker	18,800	72%

Note: Totals rounded to nearest 100.

The percentage of available capacity for the five gas oil gateway units varied from 52% for the FCC FHT to 88% for the FCC. Based on information provided by the Modernization Project applicant, the Facility purchased approximated 48,000 b/d of gas oil, including 38,000 b/d of sweet and 10,000 b/d of sour gas oil.

The URM was used to calculate unit rates, sulfur recovery and hydrogen demand, and purchased gas oil for the Facility based on the 2011 inputs summarized in Tables AQ-URM-12 to AQ-URM-14. The analysis results are presented in Table A4.3-URM-15 and compared with the operational data for 2011. The shaded rows identify the six units (the crude unit and the five gas oil gateway units) that function as URM inputs. The unshaded rows are units or other refinery operational results that are calculated by the URM.

As shown in Table A4.3-URM-15, in almost all instances the URM results are higher, and therefore more conservative, than the 2011 data for each unit and Facility activity calculated by the model. The Facility's gas oil purchases, sulfur recovery, and hydrogen plant demand were all lower in 2011 than calculated by the URM. The average daily throughput in the crude unit vacuum column, NHT, catalytic reformers, pen/hex isomerization unit, JHT and DHT was also lower during the year than calculated by the URM. The model results were lower for only three units, including the GHT and the small polymerization unit which has negligible effect on total refinery activity. Model results were also approximately 2% lower for the SDA and within the range of assay data variability that can occur over a year. The URM sulfur recovery and hydrogen demand calculations were within 0.86% and 1.16% of the 2011 operational results. As a result, the URM provides a more conservative analysis of 2011 Facility activity compared with operational data for that year.

4.3 SUMMARY OF URM SCENARIOS

This section summarizes the URM scenarios that have been developed during the preparation of the Modernization Project EIR, including:

1. Eight scenarios that are representative of crude oil blends and gas oil that could be processed by the Facility under post-Project conditions assuming that proposed Modernization Project improvements have been completed and conservative 93% and 100% of crude and gas oil gateway unit capacity utilization rates;
2. Three scenarios that analyze potential Facility operations under future conditions assuming the proposed improvements have been completed, the use of crude oil that is much heavier, much lighter and that has a higher sulfur content than Baseline Period and the Modernization Project-related cases above;

TABLE A4.3-URM-15 URM RESULTS AND 2011 FACILITY DATA

	URM Results (b/d)	2011 Unit Rates (b/d)	2011 Unit Rate vs. URM Results (%)
Crude Oil	195,600	195,600	NA
Gas Oil	58,100	48,000	-21.04%
Total	**253,700**	**243,600**	**-4.15%**
Process Unit Throughput			
Crude Unit – Atmospheric Column	195,600	195,600	NA
NHT	42,200	38,300	-10.18%
Catalytic Reformers	40,400	38,400	-5.21%
Pen/Hex Isomerization Unit	22,100	21,900	-0.91%
JHT	52,300	50,900	-2.75%
DHT	26,500	25,700	-3.11%
FCC FHT	33,800	33,800	NA
FCC	70,400	70,400	NA
GHT	17,200	18,500	7.03%
Polymerization Unit	6,700	7,000	4.29%
Hydrocracker	44,500	44,500	NA
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	10,200	10,200	NA
HNC – heavy neutral hydrocracker	18,800	18,800	NA
Solvent De-Asphalting (SDA) Unit	28,400	29,000	2.07%
Sulfur Recovery Unit (SRU) (lt/day)	**351**	**348**	-0.86%
Hydrogen Plant Demand (mmscfd)	**148**	**146.3**	-1.16%

Note: Numbers rounded to nearest 100.

3. Two scenarios that analyze potential Facility operations under no-Modernization Project future conditions (i.e., no changes to the Facility related to the Modernization Project occur) assuming 93% and 100% of the crude and gas oil gateway unit capacity is utilized; and
4. Additional scenarios provided for informational purposes in Attachment 3 that analyze various crude oil blends that are highly unlikely or technically

infeasible to be used the Facility due to factors such as cost, availability, accessibility, fractional properties that are incompatible with the range of crudes that the Facility is designed to process, or chemical properties, such as excessive acidity that would damage certain Facility processing units.

4.3.1 Modernization Project-Related Cases

This section summarizes the URM analysis of a range of project cases that are representative of potential crude oil blends and gas oils that could be run by the refinery post-Modernization Project, and assumes that the Facility operates at 93% and 100% of the permitted capacity of the crude and gas oil gateway units and after the Modernization Project improvements have been completed. The analysis is conservative because the Facility utilized only 89% of the crude unit capacity on an average daily basis over the Baseline Period,[12] and refineries cannot practicably operate crude and gas oil processing units at 100% of capacity for more than short intervals of time.

Four representative crude blends were analyzed at both the 93% and 100% utilization levels, including:

1. A "project crude blend" case with a higher sulfur content than the Baseline Period blend (2.5% versus 1.58% during the Baseline Period) and an API gravity that is slightly lower than the Baseline Period (31.6º API versus 33.7º API during the Baseline Period;
2. A "lightest crude blend" case with the highest API that can achieve the specified 93% and 100% utilization rates without exceeding the NHT unit's processing capacity;
3. A "heaviest crude blend" case with the lowest API that can achieve the specified 93% and 100% utilization rates without exceeding the SDA unit's processing capacity; and
4. A "most sour crude blend" case that can achieve the specified 93% and 100% utilization rates and that would recover sulfur in an amount that approximates the maximum SRU limit of 900 lt/d that is part of the Modernization Project.

The crude oil blends that were used in each case were identified by considering a range of potential crude oil supplies, and optimizing the crude blends to meet the specific 93% and 100% Utilization scenarios and that contain sulfur in amounts consistent with the Modernization Project's objective of increasing the

[12] As discussed in Attachment 5, on an average daily basis the Facility utilized 76% of the crude unit during 2011.

sulfur processing capacity of the Facility. Potential crude oil blends that generate significantly less sulfur than the Facility's current processing capacity of 600 lt/d, for example, could be used under current conditions and without upgrading the SRU and related facilities as proposed by the Modernization Project. Crude oils that, for reasons including cost, accessibility, reliability and chemistry (such as excessive acidity) that are highly unlikely or that cannot reliably be used by the Facility as currently configured were also not considered because such crudes are not representative of crude oil feedstocks that might be used under reasonably foreseeable post-Modernization Project operating conditions.

Table A4.3-URM-16 summarizes the crude oil blends used in the URM analysis of reasonably foreseeable future operations at 93% utilization of the crude and gas oil gateway unit capacity.

TABLE A4.3-URM-16 CRUDE OIL BLENDS, 93% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION (BARRELS PER DAY)

Crude Oil Source	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Arab Light	96,910	-	180,100	-
Basrah	142,290	127,200	-	228,200
Bakken	-	112,000	-	-
Eocene	-	-	59,100	11,000
TOTAL	**239,200**	**239,200**	**239,200**	**239,200**

Note: All numbers rounded to 100.

As discussed in Section II, the URM requires several inputs, including the level of crude and gas oil gateway unit capacity utilization, and crude oil fractions and crude and gas oil sulfur content information based on assay data. Table A4.3-URM-17 summarizes the inputs used in the URM analysis of reasonably foreseeable future operations at 93% utilization of the crude and gas oil gateway unit capacity.

Table A4.3-URM-18 summarizes the amount of crude oil and purchased gas oil, and the average daily unit rates (b/d processed by each unit) for each of the four representative cases assuming 93% utilization of the crude and gas oil gateway unit capacity.

TABLE A4.3-URM-17 URM INPUTS, PROJECT-RELATED CASES, 93% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	93%	93%	93%	93%
Crude Oil Fractions (% Each Boiling Point Range from Assay Data, °F)				
Butane and Lighter Fractions	1.93	2.53	1.29	2.16
Naphtha (55-290)	17.36	21.01	14.87	16.85
Kerosene (290-510)	21.11	23.17	20.04	19.87
Diesel (510-625)	10.62	10.85	10.76	10.14
Gas Oil (625-770)	12.58	11.93	13.13	12.03
Heavy Oil (770-1020)	18.11	16.65	19.01	18.07
Residuum (1020+)	18.30	13.87	20.90	20.91
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)				
Crude Oil API Gravity (degrees)	31.6	35.3	29.2	30.0
Crude Oil Specific Gravity	0.868	0.848	0.881	0.876
Crude Oil Sulfur Content	2.50	1.68	2.61	2.98
Sour Gas Oil Sulfur Content	2.25	2.25	2.25	2.25
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	55	55	55	60

TABLE A4.3-URM-18 URM PROJECT-RELATED CASE CALCULATIONS, 93% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Crude and Purchased Gas Oil Use (b/d				
Crude Oil	239,200	239,200	239,200	239,200
Sweet Gas Oil	3,700	3,700	3,700	3,700
Sour Gas Oil	50,000	62,600	42,000	46,900
TOTAL	292,900	305,500	284,900	289,800

TABLE A4.3-URM-18 URM PROJECT-RELATED CASE CALCULATIONS, 93% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Refinery Unit Rates (b/d)				
Crude Unit– Atmospheric Column	239,200	239,200	239,200	239,200
Crude Unit - Vacuum Column	106,700	91,600	115,900	111,900
NHT	48,500	57,600	42,400	47,100
Catalytic Reformers	45,500	51,300	41,500	44,500
Pen/Hex Isomerization Unit	25,200	29,400	22,300	24,500
JHT	60,800	65,800	58,300	57,800
DHT	29,900	30,500	30,300	28,800
FCC	74,400	74,400	74,400	74,400
FCC FHT	74,400	74,400	74,400	74,400
GHT	18,200	18,200	18,200	18,200
Alkylation Unit	25,800	25,800	25,800	25,800
Polymerization Unit	7,100	7,100	7,100	7,100
Hydrocracker	47,700	47,700	47,700	47,700
Richmond Lube Oil Plant (RLOP)				
LNC – light neutral hydrocracker	15,300	15,300	15,300	15,300
LNF – light neutral hydrofinisher	20,500	20,500	20,500	20,500
HNC – heavy neutral hydrocracker	24,200	24,200	24,200	24,200
HNF – heavy neutral hydrofinisher	11,200	11,200	11,200	11,200
Solvent De-Asphalting (SDA) Unit	43,800	33,200	50,000	50,000
Sulfur Recovery Unit (SRU)(lt/day)	749	587	758	834
Hydrogen Plant production (mmscfd)	197	178	202	205

Note: Numbers rounded to 100.

As shown in Table A4.3-URM-18, the crude and gas oil gateway units (the FCC, FCC FHT, hydrocracker, LNC and HNC) each operate at 93% of future utilization capacity (i.e., including Modernization Project-related capacity changes to the FCC FHT). The lightest crude blend case uses all of the capacity of the NHT (57,600 b/d). The heaviest and most sour crude blend cases use the full capacity of the SDA (50,000 b/d). The lightest blend case generates the highest level of crude and purchased gas oil use, 305,500 b/d compared with project crude blend case crude and gas oil use of 292,900 b/d. Sulfur recovery ranges from 587 lt/d in the lightest crude blend case to 834 lt/d in the most sour crude blend case. The Facility's hydrogen supply from the hydrogen plant (i.e., net of hydrogen obtained from internal processing and recovered from gas fuel) ranges from 178 mmscfd in the lightest crude blend case to 205 mmscfd in the most sour crude blend case.

Table A4.3-URM-19 summarizes the crude oil blends used and Table A4.3-URM-20 summarizes the inputs used in the URM analysis of reasonably foreseeable future operations at 100% of the crude and gas oil gateway unit utilization capacity.

In certain cases, the crude oil blends that allow for Facility operations at 100% of the crude and gas oil gateway unit capacity are different than the comparable blends in the 93% utilization cases. The amount of heavier blends that the Facility can process, for example, can be constrained by the SDA processing capacity. The Facility can use a crude blend with a greater percentage of residuum at 93% utilization than at 100% utilization. As a result, the heaviest crude blend API at 93% utilization is 29.2º (see Table A4.3-URM-17) compared with 30.3º at 100% utilization (see Table A4.3-URM-20). Due to the lighter fraction processing limit of the NHT, the lightest crude blend API at 100% utilization is 35.0º compared with 35.3 at 93% utilization (see Table A4.3-URM-17)

Table A4.3-URM-21 summarizes the amount of crude oil and purchased gas oil, and the average daily unit rates (barrels per day processed by each unit) for each of the four reasonably foreseeable cases assuming 100% utilization of the crude and gas oil gateway unit capacity.

As shown in Table A4.3-URM-21, the crude and gas oil gateway units (the FCC, FCC FHT, hydrocracker, LNC and HNC) each operate at 100% of future utilization capacity (i.e., including Modernization Project-related capacity changes to the FCC FHT). The lightest crude blend case uses all of the capacity of the NHT (57,600 b/d). The heaviest and most sour crude blend cases use the full capacity of the SDA (50,000 b/d). The lightest blend case generates the highest level of crude and purchased gas oil use, 324,300 b/d compared with crude and purchased gas oil use of 315,200 b/d in the project blend crude case. Sulfur recovery ranges from 600 lt/d in the lightest crude blend case to 869 lt/d in the most sour crude blend case. The Facility's hydrogen supply from the hydrogen plant (i.e., net of hydrogen obtained from internal processing and recovered from gas fuel) ranges from 192 mmscfd in the lightest crude blend case to 217 mmscfd in the most sour crude blend case.

TABLE A4.3-URM-19 CRUDE OIL BLENDS, 100% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION (BARRELS PER DAY)

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Arab Light	104,200	195,200	211,200	39,200
Basrah	153,000	–	–	218,000
Bakken	–	62,000	–	–
Eocene	–	–	46,000	–
TOTAL	**257,200**	**257,200**	**257,200**	**257,200**

TABLE A4.3-URM-20 URM INPUTS, PROJECT-RELATED CASES, 100% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	100%	100%	100%
Crude Oil Fractions (% Each Boiling Point Range from Assay Data, °F)				
Butane and Lighter Fractions	1.93	1.82	1.34	2.12
Naphtha (55-290)	17.36	19.30	15.58	17.34
Kerosene (290-510)	21.11	23.43	20.70	20.55
Diesel (510-625)	10.62	11.34	10.90	10.34
Gas Oil (625-770)	12.58	13.02	13.20	12.23
Heavy Oil (770-1020)	18.11	17.61	18.84	18.00
Residuum (1020+)	18.30	13.48	19.44	19.44
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)				
Crude Oil API Gravity (Degrees)	31.6	35.0	30.3	31.0
Crude Oil Specific Gravity	0.868	0.850	0.875	0.871
Crude Oil Sulfur Content	2.50	1.50	2.42	2.75
Sour Gas Oil Sulfur Content	2.25	2.25	2.25	2.25
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	55	45	50	55

TABLE A4.3-URM-21 URM PROJECT-RELATED CASE CALCULATIONS, 100% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Project Crude Blend	Lightest Crude Blend	Heaviest Crude Blend	Most Sour Crude Blend
Crude and Purchased Gas Oil Use (b/d)				
Crude Oil	257,200	257,200	257,200	257,200
Sweet Gas Oil	4,000	4,000	4,000	4,000
Sour Gas Oil	54,000	63,100	48,400	53,100
TOTAL	315,200	324,300	309,600	314,300
Refinery Unit Rates (b/d)				
Crude Unit – Atmospheric Column	257,200	257,200	257,200	257,200
Crude Unit - Vacuum Column	114,700	101,700	120,500	116,700
NHT	52,200	57,600	47,500	52,000
Catalytic Reformers	48,900	52,300	45,900	48,800
Pen/Hex Isomerization Unit	27,100	29,600	24,900	27,000
JHT	65,500	71,600	64,500	64,100
DHT	32,000	33,900	32,800	31,300
FCC	80,000	80,000	80,000	80,000
FCC FHT	80,000	80,000	80,000	80,000
GHT	19,500	19,500	19,500	19,500
Alkylation Unit	27,700	27,700	27,700	27,700
Polymerization Unit	7,600	7,600	7,600	7,600
Hydrocracker	51,300	51,300	51,300	51,300
Richmond Lube Oil Plant (RLOP)				
LNC – light neutral hydrocracker	16,500	16,500	16,500	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000	12,000
Solvent De-Asphalting (SDA) Unit	47,100	34,700	50,000	50,000
Sulfur Recovery Unit (SRU)(lt/day)	806	600	794	869
Hydrogen Plant production (mmscfd)	211	192	214	217

Note: Numbers rounded to nearest 100.

The URM analysis of the project, heavier, lighter and more sour crude cases at 93% and 100% of crude and gas oil gateway unit utilization capacity consider crude oil blends that range from 29.6º to 35.3º, crude oil sulfur content from 1.50% to 2.98% by weight, and total crude and purchased gas oil use of 284,900 b/d to 324,300 b/d (see Tables AQ-URM-17 to AQ-URM-18 and Tables AQ-URM-20 to AQ-URM-21). Emissions estimates for each of these cases have been prepared and are included in the Modernization Project EIR. To provide a conservative assessment, the EIR further analyzes each of these cases assuming that the hydrogen plant uses any excess production capacity above the Facility's demand as calculated by the URM and operates at 100% of proposed permitted utilization capacity. Health risk assessments have been prepared and are included in the EIR for the project crude blend and lightest crude blend cases assuming the hydrogen plant operates at 100% utilization, which is above the levels calculated by the URM for these cases.

4.3.2 Very Heavy, Very Light and Maximum Sulfur Cases

This section summarizes the URM analysis of very heavy, very light and maximum sulfur content crude cases. The purpose of this analysis is to show how the Facility processing units, the SRU and the hydrogen plant would operate in the event that the Facility used much heavier, much lighter and more sour crude oil than would occur under representative future conditions. As shown in Table A4.3-URM-22, each is based on a crude oil blend that facilitates the URM analysis of the operational consequences of processing very heavy, very light, and very sour crude oil.

TABLE A4.3-URM-22 CRUDE OIL BLEND, VERY HEAVY, VERY LIGHT AND MAXIMUM SULFUR CASES (BARRELS PER DAY)

	Very Heavy	Very Light	Maximum Sulfur
Arab Light	-	-	39,200
Basrah	-	-	218,000
Bakken	-	199,300	-
Eocene	135,000	-	-
TOTAL	**135,000**	**199,300**	**257,200**

Note: Numbers rounded to nearest 100.

Table A4.3-URM-23 summarizes the inputs used in the URM analysis of the very heavy, very light and maximum sulfur crude cases. The API of the very heavy crude oil is approximately 18.3º and the API of the very light crude oil is approximately 41º. These crude blends are substantially heavier and lighter than the average gravity of the Baseline Period crude blends (API=33.7º) and the representative project crude blend at 93% capacity (31.6º; see Table A4.3-URM-17). All three cases assume that the crude and gas oil gateway units will operate at 100% of capacity unless constrained by one or more Facility processing unit limits.

TABLE A4.3-URM-23 URM INPUTS, VERY HEAVY, VERY LIGHT, AND MAXIMUM SULFUR CASES

	Very Heavy	Very Light	Maximum Sulfur
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	100%	100%
Crude Oil Fractions (% Each Boiling Point Range from Assay Data, ºF)			
Butane and Lighter Fractions	0.67	2.87	2.12
Naphtha (55-290)	7.07	25.20	17.33
Kerosene (290-510)	12.72	26.54	20.55
Diesel (510-625)	9.24	11.61	10.34
Gas Oil (625-770)	12.30	11.82	12.23
Heavy Oil (770-1020)	20.98	15.20	17.99
Residuum (1020+)	37.02	6.77	19.44
Feedstock Input Characteristics (% Weight)			
Crude Oil API Gravity (degrees)	18.3	41.0	31.0
Crude Oil Specific Gravity	0.945	0.820	0.871
Crude Oil Sulfur Content	4.57	0.20	2.75
Sour Gas Oil Sulfur Content	2.25	2.25	2.66
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	65	20	55

Table A4.3-URM-24 summarizes the amount of crude oil and purchased gas oil, and the average daily unit rates (barrels per day processed by each unit) for the very heavy, very light and maximum sulfur crude cases assuming 100% utilization of the crude and gas oil gateway unit capacity.

TABLE A4.3-URM-24 URM VERY HEAVY, VERY LIGHT, AND MAXIMUM SULFUR CASE CALCULATIONS 100% CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	Very Heavy	Very Light	Maximum Sulfur
Crude and Purchased Gas Oil Use (b/d)			
Crude Oil	135,000	199,300	257,200
Sweet Gas Oil	4,000	4,000	4,000
Sour Gas Oil	85,900	103,200	53,000
Total	**224,900**	**306,500**	**314,200**
Refinery Unit Rates (b/d)			
Crude Unit – Atmospheric Column	135,000	199,300	257,200
Crude Unit - Vacuum Column	89,000	59,100	116,700
NHT	14,600	57,600	52,000
Catalytic Reformers	24,800	52,400	48,800
Pen/Hex Isomerization Unit	9,500	29,700	27,016
JHT	27,900	64,000	64,100
DHT	17,200	27,900	31,300
FCC	80,000	80,000	80,000
FCC FHT	80,000	80,000	80,000
GHT	19,500	19,500	19,500
Alkylation Unit	27,700	27,700	27,700
Polymerization Unit	7,600	7,600	7,600
Hydrocracker	51,300	51,300	51,300
Richmond Lube Oil Plant (RLOP)			
LNC – light neutral hydrocracker	16,500	16,500	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000
Solvent De-Asphalting (SDA) Unit	50,000	13,500	50,000
Sulfur Recovery Unit (SRU)(lt/day)	891	376	900
Hydrogen Plant production (mmscfd)	228	167	219

Note: Numbers rounded to nearest 100.

The URM results for the very heavy case results show that the Facility is unable to utilize the full capacity of the crude unit (257,200 b/d) when the crude oil blend feedstock contains more than 50,000 b/d of residuum. All of the residuum that enters the Facility is processed by the SDA which, due to equipment limitations and other factors operates at an annual average throughput of 50,000 b/d, less than the current permitted capacity of 56,000 b/d. The project will lower the annual average throughput permit limits to 50,000 b/d. As shown in Table A4.3-URM-23, assay data indicates that Eocene crude oil contains approximately 37% of the residuum fraction by volume. The SDA processing limit would be reached for Eocene crude use of approximately 135,000 b/d. In general, the URM results indicate that the Facility cannot utilize the full capacity of the crude unit for any crude oil blend that contain more than approximately 19.44% residuum by volume. Crude oil blends that are significantly heavier than the representative project crude blend case (31.6º; see Tables AQ-URM-17 and AQ-URM-20) and the average Baseline Period crude blend (33.7º API) usually contain more than 19.44% of residuum by volume.

The very heavy crude case results also indicate that Facility processing of heavier crude blends with relatively high sulfur content would also tend to be constrained by the maximum SRU processing limit of 900 lt/d. As shown in Table A4.3-URM-23. Eocene crude oil has a comparatively high sulfur content of approximately 4.57% by weight. Even if Eocene crude oil contained less residuum, the Facility could not process more than 135,000 b/d without exceeding the SRU processing limit. The URM results indicate that the Facility's capacity to process high sulfur content and heavier crude would tend to be constrained by either or both the SDA and the SRU processing limits.

The URM results for the very light case show that the Facility is unable to utilize the full capacity of the crude unit (257,200 b/d) when the naphtha in the crude oil blend feedstock, plus internal refinery flows to the NHT, exceed 57,600 b/d. All of the naphtha that enters the Facility, and a small amount of naphtha produced by other Facility units, is processed by the NHT which has a maximum capacity of 57,600 b/d. As shown in Table A4.3-URM-23, assay data indicates that Bakken crude oil contains approximately 25.2% of the naphtha fraction by volume. The NHT processing limit would be reached for Bakken crude volumes of approximately 199,300 b/d plus internal Facility feeds to the unit.

The URM results for the maximum sulfur case analyze how the Facility would operate under future conditions in the event that the crude and gas oil feedstocks contain enough sulfur to fully load the SRU (result in 900 lt/d sulfur recovery), and when the crude and gas oil gateway units are run at full capacity.

This case assumes a slightly higher sour gas sulfur content than in the 100% capacity most sour crude blend case in Table A4.3-URM-21 (2.66% versus 2.25% by weight) to result in a sulfur recovery of 900 lt/d[13] in the maximum sulfur case would not exceed the maximum capacity of the SDA or NHT, and the crude unit could be operated at the unit's 257,200 b/d capacity. The total crude and purchased gas oil used by the Facility would be 314,200 b/d, and 219 mmscf of hydrogen would be supplied to the Facility from the hydrogen plant.

Emissions estimates for the very heavy, very light and maximum sulfur cases summarized in Tables AQ-URM-22 and AQ-URM-24 have been prepared and are included in the Modernization Project EIR.

4.3.3 No-Modernization Project Cases at 93% and 100% Utilization

This section summarizes the URM analysis of Facility operations under no-Modernization Project future conditions and without upgrading the Facility's processing capacity, the hydrogen plant and other improvements proposed by the Modernization Project. The Baseline Period Facility operational results summarized in Table A4.3-URM-3 represent the 89% utilization case under no-Modernization Project conditions. Table A4.3-URM-25 summarizes the URM analysis results for Facility operations at 93% and 100% of crude and gas oil gateway unit capacity under no-Modernization Project conditions and using the Baseline Period crude blend (see Table A4.3-URM-2). The results show that the Facility operations would be constrained by the existing hydrogen plant's net hydrogen output (accounting for 94% output purity) of approximately 170.2 mmscfd. Due to insufficient hydrogen supplies, the FCC FHT and the hydrocracker could not be run at permitted capacity in the 100% utilization scenario, and the FCC FHT could not operate at full capacity in the 93% utilization scenario.[14] As a result, under no-Modernization Project conditions and using the Baseline Period crude blend, the Facility could not process imported gas oil in sufficient amounts to operate the gas oil gateway units at 100% or 93% of utilization capacity.

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[13] The most sour crude blend case in Table A4.3-URM-21 results in the recovery of 869 lt/d of sulfur and a Facility demand from the hydrogen plant of 217 mmscfd. The slightly higher level of sulfur in sour gas oil assumed in the maximum sulfur case results in the recovery of 900 lt/d of sulfur and a Facility demand from the hydrogen plant of 219 mmscfd.

[14] Under no-Modernization Project conditions, the FCC FHT capacity would remain at 65,000 b/d and not increase to 80,000 b/d as proposed by the Modernization Project. The Hydrocracker capacity of 51,300 b/d would not be modified by the Modernization Project.

TABLE A4.3-URM-25 URM ANALYSIS OF NO-PROJECT REFINERY OPERATIONS, 93% AND 100% OF CRUDE AND GAS OIL GATEWAY UNIT UTILIZATION

	100% Utilization	93% Utilization
Crude and Purchased Gas Oil Use (b/d)		
Crude Oil	257,200	239,200
Sweet Gas Oil	49,300	43,200
Sour Gas Oil	6,100	13,800
Total	**312,600**	**296,200**
Refinery Unit Rates (b/d)		
Crude Unit – Atmospheric Column	257,200	239,200
Crude Unit - Vacuum Column	104,600	97,300
NHT	55,300	51,500
Catalytic Reformers	49,100	47,400
Pen/Hex Isomerization Unit	28,300	26,600
JHT	68,200	63,300
DHT	33,400	31,200
FCC FHT	30,800	31,400
FCC	80,000	74,400
GHT	19,500	18,200
Alkylation Unit	26,800	25,800
Polymerization Unit	7,600	7,100
Hydrocracker	45,400	47,700
Richmond Lube Oil Plant (RLOP)		
LNC – light neutral hydrocracker	16,500	15,300
LNF – light neutral hydrofinisher	22,000	20,500
HNC – heavy neutral hydrocracker	26,000	24,200
HNF – heavy neutral hydrofinisher	12,000	11,200
Solvent De-Asphalting (SDA) Unit	38,600	35,900
Sulfur Recovery Unit (SRU)(lt/day)	**438**	**424**
Hydrogen Plant Production (mmscfd)	**170**	**170**

Note: Numbers rounded to nearest 100.

Emissions estimates have been prepared for these cases and are included in the Modernization Project EIR. The No-Modernization Project cases are considered in more detail in the Alternatives section of the Modernization Project EIR.

4.3.4 Limited Sulfur Scenarios at 93% and 100% Utilization

This section summarizes the URM analysis of Facility operations under future conditions that include the proposed Modernization Project improvements at 93% and 100% of the crude and gas oil gateway unit capacity except that the SRU would be limited to 750 lt/d. The crude oil blend used in both of these scenarios is the same as in the 100% and 93% utilization project crude blend cases summarized in Tables AQ-URM-16 and AQ-URM-19. Table A4.3-URM-26 summarizes the fractional properties and sulfur content information input for these cases, which are the same as for the 93% and 100% utilization project crude blend cases in Tables AQ-URM-17 and AQ-URM-19.

TABLE A4.3-URM-26 URM INPUTS FOR LIMITED SULFUR CASES, 100% AND 93% CRUDE AND GAS OIL GATEWAY UTILIZATION, SRU LIMITED TO 750 LT/D

	100% Utilization	93% Utilization
Crude Oil Fractions (% Each Boiling Point Range from Assay Data, °F)		
Butane and Lighter Fractions	1.93	1.93
Naphtha (55-290)	17.36	17.36
Kerosene (290-510)	21.11	21.11
Diesel (510-625)	10.62	10.62
Gas Oil (625-770)	12.58	12.58
Heavy Oil (770-1020)	18.11	18.11
Residuum (1020+)	18.3	18.3
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)		
Crude Oil API Gravity (degrees)	31.6	31.6
Crude Oil Specific Gravity	0.868	0.868
Crude Oil Sulfur Content	2.5	2.5
Sour Gas Oil Sulfur Content	2.25	2.25
Sweet Gas Oil Sulfur Content	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	55	55

Table A4.3-URM-27 summarizes the limited sulfur case analysis results. The reduced 750 lt/d SRU limit would constrain the full use of the crude unit capacity in the 100% case. As a result, only 205,000 b/d of crude oil could be used by the Facility. In contrast, as shown in the 100% utilization project crude blend case in Table A4.3-URM-21, the Facility could use up to 257,200 b/d of crude oil with the same fractional characteristics and sulfur content if the SRU capacity was 900 lt/d. Table A4.3-URM-27 also shows that the crude unit can be operated at 93% of capacity (and with the same unit throughputs summarized for the 93% utilization project crude blend case in Table A4.3-URM-18) because the gas oil gateway units would also be run at 93% of full capacity and less sulfur from gas oil would be brought into the Facility.

Emissions estimates have been prepared for these cases and are included in the Modernization Project EIR. The limited sulfur cases are considered in more detail in the Alternatives section of the Modernization Project EIR.

4.3.5 Other URM Cases

Several URM cases were also developed during the preparation of the Modernization Project EIR with assumed crude oil blends that are highly unlikely to or that cannot reliably be used by the Facility as currently configured, or that have relatively low sulfur contents and are not consistent with Modernization Project objectives. Summaries of 41 of these cases are presented for informational purposes in Attachment 3.

4.4 CONCLUSION

The URM is designed to calculate future refinery unit throughput rates based on potential post-Modernization Project use of crude oil with varying fractional characteristics, crude and gas oil with varying sulfur contents, and varying gas and crude oil import volumes. To provide a conservative assessment, the URM maximizes crude and gas oil inputs to the extent possible subject to applicable unit throughput capacity and permit limits. The URM calculations require that a set of input values be entered into the model that characterize the crude oil's fractional characteristics and weight, and the sulfur content of the crude and purchased gas oil (see Attachment 1). This information would be derived from the applicable assay data. Once the inputs have been entered, the URM calculates the resulting process unit throughput, sulfur recovery amount, and hydrogen plant production levels using the parameters listed in Attachment 2. The URM results were utilized to estimate Facility emissions under post-Modernization Project conditions as a result of the calculated process unit throughput rates for each scenario.

TABLE A4.3-URM-27 URM ANALYSIS OF LIMITED SULFUR (750 LT/D SRU LIMIT) CASES, 93% AND 100% OF CRUDE AND GAS AND GAS OIL GATEWAY UNIT UTILIZATION

	100% Utilization	93% Utilization
Crude and Purchased Gas Oil Use (b/d)		
Crude Oil	205,000	239,200
Sweet Gas Oil	4,000	3,700
Sour Gas Oil	76,900	50,000
Total	**285,900**	**292,900**
Refinery Unit Rates (b/d)		
Crude Unit – Atmospheric Column	205,000	239,200
Crude Unit – Vacuum Column	91,400	106,700
NHT	42,400	48,500
Catalytic Reformers	42,600	45,500
Pen/Hex Isomerization Unit	22,500	25,200
JHT	54,300	60,800
DHT	26,500	29,900
FCC	80,000	74,400
FCC FHT	80,000	74,400
GHT	19,500	18,200
Alkylation Unit	27,700	25,800
Polymerization Unit	7,600	7,100
Hydrocracker	51,300	47,700
Richmond Lube Oil Plant (RLOP)		
LNC – light neutral hydrocracker	16,500	15,300
LNF – light neutral hydrofinisher	22,000	20,500
HNC – heavy neutral hydrocracker	26,000	24,200
HNF – heavy neutral hydrofinisher	12,000	11,200
Solvent De-Asphalting (SDA) Unit	37,500	43,800
Sulfur Recovery Unit (SRU)(lt/day)	**751**	**749**
Hydrogen Plant production (mmscfd)	**208**	**197**

Note: Numbers rounded to nearest 100.

4.5 REFERENCES

Chevron Data Transmittal #1, (Rev #1): BBL Balance, 2014

Chevron Data Transmittal #3C (Rev #2): H2 Plant Production Rates, 2014.

Hogan, Thomas R. 2014. Written communication to Shari Libicki, ENVIRON. February 26.

M.D. Edgar, A.D. Johnson, J.T. Pistorius, and T. Varadi. 1984. "Troubleshooting on Hydrotreating Units," National Petroleum Refiners Association Meeting, paper No. AM-84-38, p. 7.

Robert A Meyers, Handbook of Petroleum Refining Processes, Third Edition, (McGraw-Hill, 2004) page 10.27 and page 14.36.

ATTACHMENTS TO APPENDIX 4.3 - URM

APPENDIX 4.3 - URM

Attachment 1

ATTACHMENT 1
CASE-SPECIFIC URM INPUTS
(SPECIFIED OR DERIVED FROM ASSAY DATA FOR EACH CASE)

Crude and Gas Oil Gateway Unit Capacity Utilization	**%**
Crude Oil Fractional Inputs	
Crude Oil Fraction (Boiling Point Range ºF)	**Percent of Crude Blend Volume**
Butane and Lighter Fractions	%
Naphtha (55-290)	%
Kerosene (290-510)	%
Diesel (510-625)	%
Gas Oil (625-770)	%
Heavy Oil (770-1020)	%
Residuum (1020+)	%
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)	
Crude Oil Specific Gravity[a]	[value]
Crude Oil Sulfur Content (wt. %)	%
Sour Gas Oil Sulfur Content (wt. %)	%
Sweet Gas Oil Sulfur Content (wt. %)	%
Percent Crude Oil Sulfur in Residuum Fraction Processed in SDA	%

[a] Gas oil specific gravity is also a treated as a model input and is assumed to be 0.91 for all cases.

APPENDIX 4.3 - URM

Attachment 2

ATTACHMENT 2
URM ANALYSIS PARAMETERS

URM Crude Oil Fraction and Inter-Unit Feed Parameters	
Feed to Vacuum Unit--Percent of Crude Oil Fractions	
Gas Oil Fraction	65%
Heavy Gas Oil Fraction	100%
Residuum Fraction	100%
Feed to Naphtha Hydrotreater—Percent of Crude Oil Fractions or Processing Unit Feed	
Naphtha Fraction	100%
Jet Hydrotreater Feed	6.6%
FCC Feed Hydrotreater Feed	4%
Feed to Catalytic Reformers—Percent of Processing Unit Output	
Naphtha Hydrotreater Feed	64%
Hydrocracker Feed	30%
Feed to Pen/Hex Isomerization Unit—Percent Processing Unit Output	
Naphtha Hydrotreater Feed	36%
Catalytic Reformers Feed	17%
Feed to Jet Hydrotreater—Percent of Crude Oil Fractions or Processing Unit Feed	
Kerosene Fraction (less 1,700 b/d)	100%
LNC Feed	16%
HNC Feed	13%
Diesel Hydrotreater Feed	3.6%
FCC Feed	7.2%
Feed to Diesel Hydrotreater—Percent of Crude Oil Fractions or Processing Unit Feed	
Diesel Fraction (plus 1,700 b/d)	100%
FCC Feed	3.8%
Feed to Alkylation Unit—Percent of Processing Unit Feed	
FCC Feed	25%
Hydrocracker Feed	15%
Feed to Gasoline Hydrotreater from FCC (percent of FCC Feed)	24.4%
Feed to Polymerization Unit from FCC (percent FCC Feed)	9.5%
Percent of Residuum Fraction Feed Solvent De-Asphalting (SDA) Unit	100%

FCC FHT Feed to FCC (percent FCC FHT Feed)	92%
FCC Feed from Heavy Neutral Hydrocracker (HNC) (percent HNC Feed)	9.4%
Hydrocracker Feed from FCC (percent FCC Feed)	5%
Gas Oil Parameters	
Percent Gas Oil Distilled from Atmospheric Crude Unit	35%
Percent Gas Oil Distilled from Crude Vacuum Unit	
Percent Gas Oil Fraction from Crude Vacuum Unit	65%
Percent Gas Oil From Heavy Gas Oil Fraction	100%
Percent DAO Recovered from SDA Feed	72%
Sulfur Calculation Parameters	
Residuum Specific Gravity	1.15
Percent Total Sulfur Routed to SDA that remains in Fuel Oil Blendstock	50%
Percent Sulfur in Sweet Gas Oil	0.25%
Import Gas Oil Specific Gravity	0.91
Percent SDA Feed that is Fuel Oil Blendstock	28%
Baseline Period Sour Gas Oil Sulfur Content	1.5%
Hydrogen Calculation Parameters	
Hydrogen Demand per Barrel by Unit (SCF)	
Naphtha Hydrotreater	95
JHT	145
DHT	425
FCC FHT	-
Purchased gas oil+ gas oil from crude	630
SDA-Produced gas oil + recycled	950
Hydrocracker	2150
GHT	60
Pen/Hex Isomerization Unit	295
Richmond Lube Oil Plant (RLOP)	-
LNC – light neutral hydrocracker	1,100
LNF – light neutral hydrofinisher	150
HNC – heavy neutral hydrocracker	1,100
HNF – heavy neutral hydrofinisher	250

Butamer Unit (mmscfd)	0.3
Hydrogen produced by the Catalytic Reformers (SCF per Barrel)	850
Hydrogen recovered from fuel gas	
Percent of H2 fed to units purged to fuel gas	13%
Percent of H2 in Fuel Gas Stream Recovered for Use	90%
H2 Demand/ Barrel /Percent Difference from Baseline Period Content (SCF)	100

Note: See references section and notes in text for parameter sources.

APPENDIX 4.3 - URM

Attachment 3

ATTACHMENT 3
OTHER URM CASES[15]

	Case #							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	100%	100%	100%	100%	100%	93%	100%
Crude Oil Fractions (% Each Boiling Point Range from Assay Data)								
Butane and Lighter Fractions	0.0	0.7	1.1	1.8	0.9	1.0	0.4	0.8
Naphtha (55-290)	1.0	7.1	6.8	10.3	11.4	11.9	7.7	7.7
Kerosene (290-510)	6.6	12.7	10.4	11.9	12.8	15.9	14.8	15.4
Diesel (510-625)	12.2	9.2	11.8	7.6	8.7	8.3	14.4	11.8
Gas Oil (625-770)	18.8	12.3	17.1	10.4	12.1	10.0	18.1	13.6
Heavy Oil (770-1020)	30.1	21.0	26.1	18.0	19.0	17.7	23.8	22.6
Residuum (1020+)	31.3	37.0	26.8	40.0	35.1	35.2	20.9	28.1
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)								
Crude Oil API Gravity (degrees)	14.4	18.3	19.3	20.6	20.9	21.5	21.6	22.05
Crude Oil Specific Gravity	0.970	0.945	0.939	0.930	0.929	0.925	0.924	0.922
Crude Oil Sulfur Content	1.05	4.57	1.03	4.63	4.68	3.4	0.70	0.74
Sour Gas Oil Sulfur Content	1.50	1.50	1.50	1.50	1.50	1.50	2.25	1.50

[15] These cases use crude oil blends that are highly unlikely to or that cannot reliably be used by the Facility as currently configured, or that have relatively low sulfur content and are not consistent with Modernization Project objectives.

	Case #							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	50	65	50	60	65	65	47	50
Crude and Purchased Gas Oil Use (b/d)								
Crude Oil	159,700	135,000	186,860	125,000	142,500	142,200	239,200	178,000
Sweet Gas Oil	4,000	4,000	4,000	4,000	4,000	4,000	3,700	4,000
Sour Gas Oil	52,700	85,900	50,100	95,200	86,400	91,300	18,700	66,300
Total	**216,400**	**224,900**	**240,960**	**224,200**	**232,900**	**237,300**	**261,600**	**248,300**
Refinery Unit Rates (b/d Except Where Noted)								
Crude Unit – Atmospheric Column	159,700	135,000	186,860	125,000	142,500	142,200	239,200	178,000
Crude Unit - Vacuum Column	117,500	89,000	119,500	81,000	88,300	84,400	135,000	106,000
NHT	6,200	14,600	17,900	17,800	21,300	22,400	24,400	19,400
Catalytic Reformers	19,500	24,800	27,000	26,900	29,200	29,800	30,000	27,900
Pen/Hex Isomerization Unit	5,500	9,500	11,000	11,000	12,600	13,100	13,900	11,700
JHT	21,600	27,900	30,500	25,400	29,000	33,200	46,000	38,400
DHT	24,200	17,200	26,800	14,300	17,200	16,600	38,900	25,700
FCC FHT	80,000	80,000	80,000	80,000	80,000	80,000	74,400	80,000
FCC	80,000	80,000	80,000	80,000	80,000	80,000	74,400	80,000
GHT	19,500	19,500	19,500	19,500	19,500	19,500	18,200	19,500
Alkylation Unit	27,700	27,700	27,700	27,700	27,700	27,700	25,800	27,700
Polymerization Unit	7,600	7,600	7,600	7,600	7,600	7,600	7,100	7,600

	Case #							
	1	2	3	4	5	6	7	8
Hydrocracker	51,300	51,300	51,300	51,300	51,300	51,300	47,700	51,300
Richmond Lube Oil Plant (RLOP)								
LNC – light neutral hydrocracker	16,500	16,500	16,500	16,500	16,500	16,500	15,300	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000	22,000	22,000	22,000	20,500	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000	26,000	26,000	26,000	24,200	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000	12,000	12,000	12,000	11,200	12,000
Solvent De-Asphalting (SDA) Unit	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Sulfur Recovery Unit (SRU) (lt/day)	**304**	**799**	**320**	**793**	**839**	**668**	**246**	**285**
Hydrogen Plant production (mmscfd)	**193**	**221**	**189**	**219**	**222**	**209**	**174**	**186**
Crude Oil Blend (barrels per day)								
Alaskan North Slope			60,460					
Arab Extra Light								
Arab Light								
Arab Medium								
Basrah								
Kern River	159,700		126,400				138,700	
Bakken								
Peace River Heavy					142,500			
Eocene		135,000						
Cupiagua								

	Case #							
	1	2	3	4	5	6	7	8
Murban								
Bonny Light							100,500	
Northwest Shelf Condensate								
Kuito								178,000
Maya						142,200		
Peace Light								
Gulf of Suez								
Seal Heavy				125,000				
Oriente								

	Case #							
	9	10	11	12	13	14	15	16
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	100%	100%[1]	100%[1]	100%	100%	100%	100%[1]
Crude Oil Fractions (% Each Boiling Point Range From Assay Data)								
Butane and Lighter Fractions	0.4	1.4	1.0	1.0	1.1	1.1	1.3	2.2
Naphtha (55-290)	8.6	10.4	11.9	11.9	13.4	13.4	14.4	16.8
Kerosene (290-510)	15.9	17.1	17.1	17.1	18.6	18.6	20.3	19.9
Diesel (510-625)	14.7	10.7	11.6	11.6	11.5	11.5	11.4	10.1
Gas Oil (625-770)	18.1	12.3	15.2	15.2	14.7	14.7	13.5	12.0
Heavy Oil (770-1020)	22.9	19.8	22.3	22.3	21.2	21.2	19.7	18.1
Residuum (1020+)	19.4	28.3	20.9	20.9	19.4	19.4	19.4	20.9
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)								
Crude Oil API Gravity (degrees)	22.7	24.0	26.3	26.3	28.2	28.2	29.6	30
Crude Oil Specific Gravity	0.918	0.910	0.876	0.876	0.886	0.886	0.878	0.876
Crude Oil Sulfur Content	0.65	1.59	1.59	1.59	1.67	1.67	1.55	2.98
Sour Gas Oil Sulfur Content	2.25	1.50	2.00	8.50	8.04	1.50	1.50	2.00
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	46	60	45	45	45	50	50	55
Crude and Purchased Gas Oil Use (b/d)								
Crude Oil	257,200	176,500	239,200	239,200	257,200	257,200	257,200	239,200
Sweet Gas Oil	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
Sour Gas Oil	25,500	74,100	41,000	41,000	38,300	38,300	45,500	58,800

	Case #							
	9	10	11	12	13	14	15	16
Total	**286,700**	**254,600**	**284,200**	**284,200**	**299,500**	**299,500**	**306,700**	**302,000**
Refinery Unit Rates (b/d Except Where Noted)								
Crude Unit – Atmospheric Column	257,200	176,500	239,200	239,200	257,200	257,200	257,200	239,200
Crude Unit - Vacuum Column	139,000	99,100	127,100	127,100	129,200	129,200	123,100	111,900
NHT	28,800	24,300	35,100	35,100	41,600	41,600	44,500	47,400
Catalytic Reformers	33,900	31,100	37,900	37,900	42,100	42,100	44,000	45,800
Pen/Hex Isomerization Unit	16,100	14,000	19,100	19,100	22,100	22,100	23,500	24,800
JHT	52,600	41,000	52,200	52,200	59,100	59,100	63,500	58,600
DHT	42,500	23,600	32,400	32,400	34,300	34,300	34,100	29,000
FCC FHT	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
FCC	80,000	80,000	80,000	80,000	80,000	80,000	80,000	80,000
GHT	19,500	19,500	19,500	19,500	19,500	19,500	19,500	19,500
Alkylation Unit	27,700	27,700	27,700	27,700	27,700	27,700	27,700	27,700
Polymerization Unit	7,600	7,600	7,600	7,600	7,600	7,600	7,600	7,600
Hydrocracker	51,300	51,300	51,300	51,300	51,300	51,300	51,300	51,300
Richmond Lube Oil Plant (RLOP)								
LNC – light neutral hydrocracker	16,500	16,500	16,500	16,500	16,500	16,500	16,500	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000	26,000	26,000	26,000	26,000	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000

	Case #							
	9	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Solvent De-Asphalting (SDA) Unit	50,000	50,000	50,000	50,000	50,000	50,000	50,000	50,000
Sulfur Recovery Unit (SRU)(lt/day)	**267**	**439**	**521**	**900**	**900**	**529**	**509**	**876**
Hydrogen Plant production (mmscfd)	**186**	**194**	**199**	**226**	**223**	**197**	**194**	**218**
Crude Oil Blend (b/d)								
Alaskan North Slope								
Arab Extra Light								
Arab Light			158,500	158,500	194,500	194,500	178,300	
Arab Medium								
Basrah								228,200
Kern River	134,000		80,700	80,700	62,700	62,700		
Bakken								
Peace River Heavy								
Eocene								11,000
Cupiagua								
Murban								
Bonny Light	123,200							
Northwest Shelf Condensate								
Kuito							78,900	
Maya								
Peace Light								

	Case #							
	9	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Gulf of Suez								
Seal Heavy								
Oriente		176,500						

	Case #							
	17	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%[1]	100%	100%[1]	100%	93%	93%	100%	100%
Crude Oil Fractions (% Each Boiling Point Range From Assay Data)								
Butane and Lighter Fractions	2.2	1.5	2.2	1.4	2.2	2.2	1.4	1.5
Naphtha (55-290)	16.8	15.3	17.3	16.2	17.3	17.3	16.4	16.3
Kerosene (290-510)	19.9	20.8	20.2	20.5	20.2	20.2	21.1	20.8
Diesel (510-625)	10.1	11.1	10.2	10.8	10.2	10.2	10.7	10.7
Gas Oil (625-770)	12.0	13.1	12.0	13.1	12.0	12.0	12.7	12.9
Heavy Oil (770-1020)	18.1	18.8	17.9	18.5	17.9	17.9	18.2	18.3
Residuum (1020+)	20.9	19.4	20.1	19.4	20.1	20.1	19.4	19.4
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)								
Crude Oil API Gravity (degrees)	30	30.3	30.6	30.6	30.6	30.6	30.8	31.1
Crude Oil Specific Gravity	0.876	0.874	0.873	0.873	0.873	0.873	0.872	0.870
Crude Oil Sulfur Content	2.98	1.8	2.90	2.48	2.90	2.90	2.21	2.36
Sour Gas Oil Sulfur Content	2.29	1.50	1.50	1.50	2.25	3.42	1.50	1.50
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	55	50	55	50	60	60	50	50
Crude and Purchased Gas Oil Use (b/d)								
Crude Oil	239,200	257,200	248,500	257,200	239,200	239,200	257,200	257,200
Sweet Gas Oil	4,000	4,000	4,000	4,000	3,700	3,700	4,000	4,000
Sour Gas Oil	58,800	48,800	56,300	49,400	48,600	48,600	51,100	50,400

	Case #							
	17	18	19	20	21	22	23	24
Total	**302,000**	**310,000**	**308,800**	**310,600**	**291,500**	**291,500**	**312,300**	**311,600**
Refinery Unit Rates (b/d Except Where Noted)								
Crude Unit – Atmospheric Column	239,200	257,200	248,500	257,200	239,200	239,200	257,200	257,200
Crude Unit - Vacuum Column	111,900	120,200	114,000	119,600	109,700	109,700	118,200	118,700
NHT	47,400	46,900	50,300	49,200	48,300	48,300	49,600	49,400
Catalytic Reformers	45,800	45,500	47,700	47,000	45,300	45,300	47,200	47,100
Pen/Hex Isomerization Unit	24,800	24,600	26,200	25,700	25,100	25,100	25,900	25,800
JHT	58,600	64,800	61,400	64,100	58,600	58,600	65,600	64,700
DHT	29,000	33,300	30,000	32,400	28,900	28,900	32,200	32,200
FCC FHT	80,000	80,000	80,000	80,000	74,400	74,400	80,000	80,000
FCC	80,000	80,000	80,000	80,000	74,400	74,400	80,000	80,000
GHT	19,500	19,500	19,500	19,500	18,200	18,200	19,500	19,500
Alkylation Unit	27,700	27,700	27,700	27,700	25,800	25,800	27,700	27,700
Polymerization Unit	7,600	7,600	7,600	7,600	7,100	7,100	7,600	7,600
Hydrocracker	51,300	51,300	51,300	51,300	47,700	47,700	51,300	51,300
Richmond Lube Oil Plant (RLOP)								
LNC – light neutral hydrocracker	16,500	16,500	16,500	16,500	15,300	15,300	16,500	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000	22,000	20,500	20,500	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000	26,000	24,200	24,200	26,000	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000	12,000	11,200	11,200	12,000	12,000

	Case #							
	17	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Solvent De-Asphalting (SDA) Unit	50,000	50,000	50,000	50,000	48,200	48,200	50,000	50,000
Sulfur Recovery Unit (SRU)(lt/day)	900	580	834	759	819	900	691	728
Hydrogen Plant production (mmscfd)	220	198	214	210	202	208	205	208
Crude Oil Blend (b/d)								
Alaskan North Slope								
Arab Extra Light								
Arab Light		179,900		206,500			206,800	216,800
Arab Medium								
Basrah	228,200		248,500		239,200	239,200		
Kern River								
Bakken								
Peace River Heavy				50,700				
Eocene	11,000							
Cupiagua								
Murban								
Bonny Light								
Northwest Shelf Condensate								
Kuito								
Maya							50,400	
Peace Light								

	Case #							
	17	18	19	20	21	22	23	24
Gulf of Suez								
Seal Heavy								40,400
Oriente		77,300						

	Case #							
	25	26	27	28	29	30	31	32
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	93%[2]	100%[1]	100%	93%	100%	100%	100%[1]
Crude Oil Fractions (% Each Boiling Point Range From Assay Data)								
Butane and Lighter Fractions	1.8	1.6	1.6	2.2	2.2	1.2	1.7	1.3
Naphtha (55-290)	15.5	17.4	17.4	19.3	19.3	19.1	19.4	20.7
Kerosene (290-510)	20.3	22.2	22.2	22.1	22.1	25.9	22.8	25.8
Diesel (510-625)	11.1	11.1	11.1	11.2	11.2	16.8	11.5	16.3
Gas Oil (625-770)	12.8	13.3	13.3	13.0	13.0	16.5	13.2	16.0
Heavy Oil (770-1020)	19.1	18.3	18.3	17.3	17.3	14.3	17.7	13.8
Residuum (1020+)	19.3	16.1	16.1	15.0	15.0	6.2	13.7	6.0
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)								
Crude Oil API Gravity (degrees)	31.3	32.9	32.9	33.7	33.7	34.1	34.7	34.9
Crude Oil Specific Gravity	0.869	0.861	0.861	0.857	0.857	0.854	0.851	0.850
Crude Oil Sulfur Content	1.41	2.00	2.00	1.58	1.58	0.15	1.62	0.15
Sour Gas Oil Sulfur Content	1.50	2.00	4.43	2.25	2.25	2.25	1.50	2.00
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	50	45	45	50	50	25	50	25
Crude and Purchased Gas Oil Use (b/d)								
Crude Oil	257,200	239,200	239,200	257,200	239,200	257,200	257,200	239,200
Sweet Gas Oil	4,000	4,000	4,000	4,000	3,700	4,000	4,000	4,000
Sour Gas Oil	48,900	63,500	63,500	61,200	56,700	76,000	61,900	85,100

	Case #							
	25	26	27	28	29	30	31	32
TOTAL	310,100	306,700	306,700	322,400	299,596	337,200	323,100	328,300
Refinery Unit Rates (b/d Except Where Noted)								
Crude Unit – Atmospheric Column	257,200	239,200	239,200	257,200	239,196	257,200	257,200	239,200
Crude Unit - Vacuum Column	120,200	102,900	102,900	104,600	97,300	80,400	102,500	72,300
NHT	47,300	49,100	49,100	57,300	53,300	57,600	57,600	57,600
Catalytic Reformers	45,800	46,900	46,900	52,200	48,500	52,400	52,400	52,400
Pen/Hex Isomerization Unit	24,800	25,700	25,700	29,500	27,400	29,600	29,600	29,600
JHT	63,500	64,300	64,300	68,200	63,300	78,300	70,000	73,300
DHT	33,300	31,400	31,400	33,400	31,200	47,900	34,300	43,800
FCC FHT	80,000	80,000	80,000	80,000	74,400	80,000	80,000	80,000
FCC	80,000	80,000	80,000	80,000	74,400	80,000	80,000	80,000
GHT	19,500	19,500	19,500	19,500	18,200	19,500	19,500	19,500
Alkylation Unit	27,700	27,700	27,700	27,700	25,800	27,700	27,700	27,700
Polymerization Unit	7,600	7,600	7,600	7,600	7,100	7,600	7,600	7,600
Hydrocracker	51,300	51,300	51,300	51,300	47,700	51,300	51,300	51,300
Richmond Lube Oil Plant (RLOP)								
LNC – light neutral hydrocracker	16,500	16,500	16,500	16,500	15,300	16,500	16,500	16,500
LNF – light neutral hydrofinisher	22,000	22,000	22,000	22,000	20,500	22,000	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	26,000	26,000	26,000	24,200	26,000	26,000	26,000
HNF – heavy neutral hydrofinisher	12,000	12,000	12,000	12,000	11,200	12,000	12,000	12,000

	Case #							
	25	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Solvent De-Asphalting (SDA) Unit	49,600	38,400	38,400	38,600	35,900	16,000	35,200	14,400
Sulfur Recovery Unit (SRU) (lt/day)	**475**	**680**	**900**	**605**	**562**	**290**	**549**	**285**
Hydrogen Plant production (mmscfd)	**190**	**202**	**217**	**193**	**179**	**176**	**188**	**165**
Crude Oil Blend (b/d)								
Alaskan North Slope				68,233	63,457			
Arab Extra Light				62,985	58,576			
Arab Light		214,830	214,830	83,988	78,109		215,000	
Arab Medium				7,877	7,326			
Basrah		24,370	24,370	28,869	26,848			
Kern River								
Bakken								
Peace River Heavy								
Eocene								
Cupiagua							42,200	
Murban				5,248	4,880			
Bonny Light						244,820		219,700
Northwest Shelf Condensate						12,380		19,500
Kuito								
Maya								
Peace Light								

	Case #							
	25	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Gulf of Suez	257,200							
Seal Heavy								
Oriente								

	Case #						
	33	**34**	**35**	**36**	**37**[1]	**38**	**39**
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	100%	93%	93%	100%	100%	100%	100%
Crude Oil Fractions (% Each Boiling Point Range From Assay Data)							
Butane and Lighter Fractions	1.4	1.3	1.8	2.5	3.0	N/A	N/A
Naphtha (55-290)	19.1	20.8	20.8	18.7	29.2	N/A	N/A
Kerosene (290-510)	26.2	25.8	26.3	25.0	24.8	N/A	N/A
Diesel (510-625)	15.8	16.3	14.7	11.7	12.6	N/A	N/A
Gas Oil (625-770)	15.8	16.0	14.7	12.9	12.2	N/A	N/A
Heavy Oil (770-1020)	15.1	13.8	15.1	16.1	14.4	N/A	N/A
Residuum (1020+)	6.6	6.0	6.7	13.2	3.9	N/A	N/A
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)							
Crude Oil API Gravity (degrees)	35.0	35.1	36.6	39.9	43.1	N/A	N/A
Crude Oil Specific Gravity	0.850	0.849	0.842	0.826	0.810	N/A	N/A
Crude Oil Sulfur Content	0.17	0.15	0.18	0.43	0.08	N/A	N/A
Sour Gas Oil Sulfur Content	2.25	2.25	2.25	1.50	1.50	2.25	3.79
Sweet Gas Oil Sulfur Content	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA	20	25	20	20	30		
Crude and Purchased Gas Oil Use (b/d)							
Crude Oil	257,200	239,200	239,200	257,200	174,300	N/A	N/A
Sweet Gas Oil	4,000	3,700	3,700	4,000	4,000	4,000	4,000

	Case #						
	33	**34**	**35**	**36**	**37**[1]	**38**	**39**
Sour Gas Oil	75,200	73,300	72,100	67,800	115,500	166,800	166,800
Total	**336,400**	**316,200**	**315,000**	**329,000**	**293,800**	**170,800**	**170,800**
Refinery Unit Rates (b/d Except Where Noted)							
Crude Unit – Atmospheric Column	257,200	239,200	239,200	257,200	174,300	N/A	N/A
Crude Unit - Vacuum Column	82,100	72,200	74,900	96,900	45,700	N/A	N/A
NHT	57,600	57,600	57,600	56,200	57,600	4,000	4,000
Catalytic Reformers	52,400	51,300	51,200	51,500	52,400	18,000	18,000
Pen/Hex Isomerization Unit	29,600	29,400	29,400	29,000	29,600	4,500	4,500
JHT	79,000	72,500	73,500	75,600	54,300	11,900	11,900
DHT	45,500	43,600	39,600	34,800	26,700	3,000	3,000
FCC FHT	80,000	74,400	74,400	80,000	80,000	80,000	80,000
FCC	80,000	74,400	74,400	80,000	80,000	80,000	80,000
GHT	19,500	18,200	18,200	19,500	19,500	19,500	19,500
Alkylation Unit	27,700	25,800	25,800	27,700	27,700	27,700	27,700
Polymerization Unit	7,600	7,100	7,100	7,600	7,600	7,600	7,600
Hydrocracker	51,300	47,700	47,700	51,300	51,300	51,300	51,300
Richmond Lube Oil Plant (RLOP)							
LNC – light neutral hydrocracker	16,500	15,300	15,300	16,500	16,500	16,500	16,500
LNF – light neutral hydrofinisher	22,000	20,500	20,500	22,000	22,000	22,000	22,000
HNC – heavy neutral hydrocracker	26,000	24,200	24,200	26,000	26,000	26,000	26,000

	Case #						
	33	**34**	**35**	**36**	**37**[1]	**38**	**39**
HNF – heavy neutral hydrofinisher	12,000	11,200	11,200	12,000	12,000	12,000	12,000
Solvent De-Asphalting (SDA) Unit	17,000	14,400	15,900	33,900	6,700	14,400	14,400
Sulfur Recovery Unit (SRU) (lt/day)	**294**	**277**	**283**	**274**	**263**	**535**	**900**
Hydrogen Plant production (mmscfd)	168	154	154	168	157	192	218
Crude Oil Blend (b/d)							
Alaskan North Slope						N/A	N/A
Arab Extra Light						N/A	N/A
Arab Light						N/A	N/A
Arab Medium						N/A	N/A
Basrah						N/A	N/A
Kern River						N/A	N/A
Bakken	69,500		112,500			N/A	N/A
Peace River Heavy						N/A	N/A
Eocene						N/A	N/A
Cupiagua					174,300	N/A	N/A
Murban						N/A	N/A
Bonny Light	187,700	219,200	126,700			N/A	N/A
Northwest Shelf Condensate		20,000				N/A	N/A
Kuito						N/A	N/A
Maya						N/A	N/A

	Case #						
	33	**34**	**35**	**36**	**37**[1]	**38**	**39**
Peace Light				257,200		N/A	N/A
Gulf of Suez						N/A	N/A
Seal Heavy						N/A	N/A
Oriente						N/A	N/A

	Case #	
	40	**41**
Crude and Gas Oil Gateway Unit Capacity Utilization (%)	93%	93%
Crude Oil Fractions (% Each Boiling Point Range From Assay Data)		
Butane and Lighter Fractions	N/A	N/A
Naphtha (55-290)	N/A	N/A
Kerosene (290-510)	N/A	N/A
Diesel (510-625)	N/A	N/A
Gas Oil (625-770)	N/A	N/A
Heavy Oil (770-1020)	N/A	N/A
Residuum (1020+)	N/A	N/A
Feedstock Input Characteristics (% Weight, Unless Otherwise Specified)		
Crude Oil API Gravity (degrees)	N/A	N/A
Crude Oil Specific Gravity	N/A	N/A
Crude Oil Sulfur Content	N/A	N/A
Sour Gas Oil Sulfur Content	2.25	3.79
Sweet Gas Oil Sulfur Content	0.25	0.25
Crude Oil Sulfur in Residuum Fraction Processed in SDA		
Crude and Purchased Gas Oil Use (b/d)		
Crude Oil	N/A	N/A
Sweet Gas Oil	3,700	3,700
Sour Gas Oil	154,900	154,900

	Case #	
	40	**41**
TOTAL	158,600	158,600
Refinery Unit Rates (b/d Except Where Noted)		
Crude Unit – Atmospheric Column	N/A	N/A
Crude Unit - Vacuum Column	N/A	N/A
NHT	3,700	3,700
Catalytic Reformers	16,800	16,800
Pen/Hex Isomerization Unit	4,200	4,200
JHT	11,100	11,100
DHT	2,800	2,800
FCC FHT	74,400	74,400
FCC	74,400	74,400
GHT	18,200	18,200
Alkylation Unit	25,800	25,800
Polymerization Unit	7,100	7,100
Hydrocracker	47,700	47,700
Richmond Lube Oil Plant (RLOP)		
LNC – light neutral hydrocracker	15,300	15,300
LNF – light neutral hydrofinisher	20,500	20,500
HNC – heavy neutral hydrocracker	24,200	24,200
HNF – heavy neutral hydrofinisher	11,200	11,200

	Case #	
	40	**41**
Solvent De-Asphalting (SDA) Unit	N/A	N/A
Sulfur Recovery Unit (SRU) (lt/day)	497	836
Hydrogen Plant production (mmscfd)	179	203
Crude Oil Blend (b/d)		
Alaskan North Slope	N/A	N/A
Arab Extra Light	N/A	N/A
Arab Light	N/A	N/A
Arab Medium	N/A	N/A
Basrah	N/A	N/A
Kern River	N/A	N/A
Bakken	N/A	N/A
Peace River Heavy	N/A	N/A
Eocene	N/A	N/A
Cupiagua	N/A	N/A
Murban	N/A	N/A
Bonny Light	N/A	N/A
Northwest Shelf Condensate	N/A	N/A
Kuito	N/A	N/A
Maya	N/A	N/A
Peace Light	N/A	N/A

	Case #	
	40	**41**
Gulf of Suez	N/A	N/A
Seal Heavy	N/A	N/A
Oriente	N/A	N/A

Notes:

1. Case in which gas oil gateway units operate at 100% capacity, but 100% crude unit capacity cannot be achieved due to exceedance of at least one processing unit throughput limit.
2. Case in which crude unit is limited to specified level.

Chevron

T.A. Lizarraga
Manager

Health, Environment & Safety
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June 11, 2009

Richard Mitchell
Director, Planning and Building Services
City of Richmond
450 Civic Center Plaza
Richmond, CA 94804

Chevron Richmond Refinery
Conditional Use Permit Condition D2

Dear Mr. Mitchell:

This letter provides test reports for the First Quarter 2009 6-Element Sampling at Chevron's Richmond Refinery. This information is being submitted pursuant to Condition D2 of Chevron's Conditional Use Permit, Number 1101974, for the Chevron Energy and Hydrogen Renewal Project.

Attachment 1 to this letter summarizes the results for each sample analysis required by the condition. The final results for the First Quarter 2009 samples were received by Chevron from the analytical laboratory on May 15, 2009.

Sampling was performed according to the protocol submitted to the City and BAAQMD in December, 2008. As explained in that protocol, Chevron would make subsequent improvements for sampling gas streams that should be more accurate than the "grab samples" specified in the condition and used for the Fourth Quarter 2008 samples. The following changes were implemented to improve the analytical and gas sampling monitoring:

- The analytical laboratory for the crude oil and gas oil samples was switched to Frontier GeoSciences, a leading analytical lab for mercury and other metals in petroleum hydrocarbons.
- The gas volume collected for each gas stream was increased from 6 liters to 18 liters.

The flow-through gas sampling stations are under construction. Future gas sampling volumes will be increased to 120 liters, as noted in the protocol, once the gas sampling stations are completed and tested.

If you have any questions concerning this report, please contact Ms. Karen Graul at (510) 242-4930.

Sincerely,

Tery Lizarraga

Attachment

cc: Lamont Thompson (City of Richmond)

bcc: Robert Chamberlin
Lisa Duncan
ETC Project Group c/o Ross Smart

ATTACHMENT 1 (3 pages)

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Report for Quarter Ending: 3/31/2009

Liquid Samples - Metals

Compound:	Cadmium		Test Method: ICP-MS (EPA 1638)						Date 4/26/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 3/5/09	ND	0.002	0.010		ND	0.002	0.010		ND	0.002	0.009	
Gas Oil - FCC - 3/16/09	0.002	0.002	0.009	J	ND	0.002	0.010		0.002	0.002	0.010	J
Gas Oil - TKN - 2/12/09	ND	0.002	0.010		ND	0.002	0.010		ND	0.002	0.010	
Gas Oil - TKC - 1/27/09	ND	0.002	0.010		0.007	0.002	0.008	J	ND	0.002	0.011	

Compound:	Nickel		Test Method: ICP-MS (EPA 1638)						Date 4/26/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 3/5/09	6.06	0.009	0.04		6.07	0.009	0.04		5.92	0.009	0.04	
Gas Oil - FCC - 3/16/09	1.15	0.009	0.04		1.14	0.009	0.04		1.12	0.009	0.04	
Gas Oil - TKN - 2/12/09	0.06	0.009	0.04		0.07	0.009	0.04		0.06	0.009	0.04	
Gas Oil - TKC - 1/27/09	0.42	0.009	0.04		0.45	0.008	0.03		0.45	0.010	0.04	

Compound:	Selenium		Test Method: ICP-MS (EPA 1638)						Date 5/15/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 3/5/09	0.284	0.0078	0.039		0.273	0.008	0.04		0.279	0.0076	0.038	
Gas Oil - FCC - 3/16/09	0.053	0.0078	0.037		0.062	0.0074	0.038		0.06	0.0080	0.040	
Gas Oil - TKN - 2/12/09	0.057	0.0080	0.040		0.062	0.008	0.040		0.043	0.0078	0.039	
Gas Oil - TKC - 1/27/09	0.071	0.0078	0.039		0.065	0.0068	0.034		0.076	0.0086	0.043	

Compound:	Vanadium		Test Method: ICP-MS (EPA 1638)						Date 4/26/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 3/5/09	15.7	0.100	0.100		15.8	0.100	0.100		15.4	0.09	0.09	
Gas Oil - FCC - 3/16/09	1.3	0.09	0.09		1.33	0.100	0.10		1.19	0.100	0.10	
Gas Oil - TKN - 2/12/09	0.13	0.100	0.10		0.13	0.100	0.10		0.12	0.100	0.10	
Gas Oil - TKC - 1/27/09	0.79	0.10	0.10		0.84	0.08	0.08		0.88	0.11	0.11	

Compound:	Mercury		Test Meth EPA 1631 (Cold Vapor Atomic Fluorescence Spectrometry)									
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 3/5/09	ND	0.00088	0.00242		0.00095	0.00091	0.00252	J	ND	0.00085	0.00235	
Gas Oil - FCC - 3/16/09	0.00125	0.00084	0.00233	J	0.00180	0.00087	0.00240	J	0.00133	0.00091	0.00251	J
Gas Oil - TKN - 2/12/09	ND	0.00091	0.00499		ND	0.00091	0.00481		ND	0.00088	0.00472	
Gas Oil - TKC - 1/26/09*	ND	0.00090	0.00249		ND	0.00086	0.00238		ND	0.00085	0.00235	

*TKC-1/26/09 - ship sample not collected for Hg. Used TKC feed tank sample.

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Report for Quarter Ending: 3/31/2009

Gas Samples - Metals

Compound	Mercury Date:3/31/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	RL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	DNQ	0.03		0.0201	DNQ	DNQ	0.03		0.0218	DNQ	DNQ	0.03		0.0211	DNQ
Fuel Gas - V701	DNQ	0.03		0.0191	DNQ	DNQ	0.03		0.0207	DNQ	DNQ	0.03		0.0212	DNQ
Fuel Gas - V870	0.0386	0.03		0.0211	1.83	0.0055	0.03	J	0.0222	0.248	0.0070	0.03	J	0.0214	0.327
Flare Gas - V731	0.0152	0.03	J	0.0135	1.124	DNQ	0.03		0.0149	DNQ	DNQ	0.03		0.0165	DNQ
Flare Gas - F3901	DNQ	0.03		0.0148	DNQ	DNQ	0.03		0.0149	DNQ	DNQ	0.03		0.0145	DNQ

Compound	Cadmium Date:3/31/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	RL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	ND	0.15		0.0201	ND	ND	0.15		0.0218	ND	ND	0.15		0.0211	ND
Fuel Gas - V701	ND	0.15		0.0191	ND	ND	0.15		0.0207	ND	ND	0.15		0.0212	ND
Fuel Gas - V870	ND	0.15		0.0211	ND	ND	0.15		0.0222	ND	ND	0.15		0.0214	ND
Flare Gas - V731	ND	0.15		0.0135	ND	ND	0.15		0.0148	ND	ND	0.15		0.0165	ND
Flare Gas - F3901	ND	0.15		0.0148	ND	ND	0.15		0.0149	ND	ND	0.15		0.0145	ND

Compound	Nickel Date:3/31/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	RL ug	Flag	Vol Gas dscm*	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm
Fuel Gas - V475-B	0.010	0.3	J	0.0201	0.497	0.001	0.3	J	0.0218	0.046	0.226	0.3	J	0.0211	10.71
Fuel Gas - V701	DNQ	0.3		0.0191	DNQ	DNQ	0.3		0.0207	DNQ	DNQ	0.3		0.0212	DNQ
Fuel Gas - V870	DNQ	0.3		0.0211	DNQ	DNQ	0.3		0.0222	DNQ	0.002	0.3	J	0.0214	0.093
Flare Gas - V731	DNQ	0.3		0.0135	DNQ	DNQ	0.3		0.0148	DNQ	DNQ	0.3		0.0165	DNQ
Flare Gas - F3901	0.025	0.3	J	0.0148	1.687	DNQ	0.3		0.0149	DNQ	DNQ	0.3		0.0145	DNQ

Compound	Selenium Date:3/31/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	RL ug	Flag	Vol Gas dscm*	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm
Fuel Gas - V475-B	0.26	0.3	J	0.0201	12.933	ND	0.3		0.0218	ND	ND	0.3		0.0211	ND
Fuel Gas - V701	ND	0.3		0.0191	ND	ND	0.3		0.0207	ND	ND	0.3		0.0212	ND
Fuel Gas - V870	ND	0.3		0.0211	ND	ND	0.3		0.0222	ND	ND	0.3		0.0214	ND
Flare Gas - V731	ND	0.3		0.0135	ND	ND	0.3		0.0148	ND	ND	0.3		0.0165	ND
Flare Gas - F3901	ND	0.3		0.0148	ND	ND	0.3		0.0149	ND	ND	0.3		0.0145	ND

Compound	Vanadium Date:3/31/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	RL ug	Flag	Vol Gas dscm*	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm	Result ug	RL ug	Flag	Vol Gas dscm	Conc. ug/dscm
Fuel Gas - V475-B	ND	1.5		0.0201	ND	ND	1.5		0.0218	ND	ND	0.47		0.0211	ND
Fuel Gas - V701	ND	1.5		0.0191	ND	ND	1.5		0.0207	ND	ND	0.47		0.0212	ND
Fuel Gas - V870	ND	1.5		0.0211	ND	ND	1.5		0.0222	ND	ND	0.47		0.0214	ND
Flare Gas - V731	ND	1.5		0.0135	ND	ND	1.5		0.0148	ND	ND	0.47		0.0165	ND
Flare Gas - F3901	ND	1.5		0.0148	ND	ND	1.5		0.0149	ND	ND	0.47		0.0145	ND

ATTACHMENT 1 (3 pages)

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Report for Quarter Ending: 3/31/2009

Liquid HC and Gas Samples - Total Sulfur

Compound:	Sulfur	
Source	Total Sulfur	
	wt %	mol ppm*
Liquid HC Samples - 3/27/09		
Crude Oil - Crude Unit 3/5/09	1.13	
Gas Oil - FCC - 3/16/09	0.232	
Gas Oil - TKN - 2/12/09	1.66	
Gas Oil - TKC - 1/27/09	2.24	
Gas Samples - 3/25/09		
V475-B - 3/24/09		40.4
V701 - 3/24/09		28.9
V870 - 3/24/09		38.5
V731 (NY Flare) - 3/25/09		66.6
F3901 (SY Flare) - 3/25/09		172.9

Key:

RL: Reporting Limit
MDL: Method Detection Limit
J Flag: Estimated value. Analyte detected at a level less than the Reporting Limit, but greater than or equal to the Method Detection Limit
DNQ: Detected but Not Quantified. All gas samples were blank corrected and where blank value exceeded the measured value, DNQ was denoted.
ND: Not detected
dsl: dry standard liter
dscm: dry standard cubic meter at 29.92 " Hg, 68 Deg. F (760 mm Hg 20 Deg C)
Conc: Concentration
* Limit of detection for analysis was 0.1 mol ppm. Convert to wt/wt ppm S by multiplying by factor of 2.

Chevron

December 17, 2009

Richard Mitchell
Director, Planning and Building Services
City of Richmond
1401 Marina Way South
Richmond, CA 94804

Chevron Richmond Refinery
Conditional Use Permit Condition D2

Dear Mr. Mitchell:

This letter provides the test report for Six Element Sampling at Chevron's Richmond Refinery for the Second Quarter of 2009. This information is submitted pursuant to Condition D2 of Chevron's Conditional Use Permit, Number 1101974, for the Chevron Energy and Hydrogen Renewal Project.

Sampling was performed according to the protocol submitted to the City and BAAQMD in December 2008. The final set of analytical results for Second Quarter 2009 samples were received by Chevron from the analytical laboratories on November 25, 2009.

Please find attached *Six Element Sampling Results Report for Quarter Ending June 30, 2009* which summarizes the results for each sample analysis required by the D2 condition.

If you have any questions concerning this report, please contact Ms. Winnie Lieu at (510) 242-2742.

Sincerely,

Karen Graul

for Tery Lizarraga

Attachment:
Six Element Sampling Results Report for Quarter Ending June 30, 2009

December 17, 2009

Richard Mitchell
Director, Planning and Building Services
City of Richmond
1401 Marina Way South
Richmond, CA 94804

Chevron Richmond Refinery
Conditional Use Permit Condition D2

This letter provides the test report for Six Element Sampling at Chevron's Richmond Refinery for the Second Quarter of 2009. This information is submitted pursuant to Condition D2 of Chevron's Conditional Use Permit, Number 1101974, for the Chevron Energy and Hydrogen Renewal Project.

Sampling was performed according to the protocol submitted to the City and BAAQMD in December 2008. The final set of analytical results for Second Quarter 2009 samples were received by Chevron from the analytical laboratories on November 25, 2009.

Please find attached *Six Element Sampling Results Report for Quarter Ending June 30, 2009* which summarizes the results for each sample analysis required by the D2 condition.

If you have any questions concerning this report, please contact Ms. Winnie Lieu at (510) 242-2742.

Sincerely,

Original Signed By
Karen Graul

KAG
Tery Lizarraga

Attachment:
Six Element Sampling Results Report for Quarter Ending June 30, 2009

Bcc:
Robert Chamberlain, Richmond Renewal Project
Rolf Lindenhayn, Richmond Renewal Project
ETC (c/o Matt Diaz)

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Six Element Sampling Results Report for Quarter Ending: 6/30/2009

Liquid Samples - Metals

Compound	Cadmium	Test Method: ICP-MS (EPA 1638)							Date 5/20/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 5/14/09	ND	0.002	0.015		ND	0.002	0.014		ND	0.002	0.015	
Gas Oil - FCC - 5/20/09	ND	0.002	0.015		ND	0.002	0.015		ND	0.002	0.014	
Gas Oil - TKN - 5/20/09	ND	0.002	0.015		ND	0.002	0.014		ND	0.002	0.014	
Gas Oil - TKC - 5/20/09	ND	0.002	0.015		ND	0.002	0.014		ND	0.002	0.015	

Compound	Nickel	Test Method: ICP-MS (EPA 1638)							Date 5/20/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 5/14/09	4.870	0.011	0.05		4.600	0.011	0.049		5.08	0.011	0.049	
Gas Oil - FCC - 5/20/09	0.144	0.011	0.048		0.146	0.011	0.05		0.140	0.011	0.05	
Gas Oil - TKN - 5/20/09	0.061	0.011	0.05		0.071	0.011	0.049		0.069	0.010	0.047	
Gas Oil - TKC - 5/20/09	0.147	0.011	0.05		0.15	0.011	0.049		0.152	0.011	0.048	

Compound	Selenium	Test Method: ICP-MS (EPA 1638)							Date 5/20/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 5/14/09	0.346	0.018	0.04		0.320	0.017	0.039		0.346	0.018	0.039	
Gas Oil - FCC - 5/20/09	0.060	0.018	0.04		0.042	0.018	0.04		ND	0.018	0.04	
Gas Oil - TKN - 5/20/09	0.214	0.0080	0.040		0.224	0.017	0.039		0.194	0.017	0.037	
Gas Oil - TKC - 5/20/09	ND	0.018	0.039		ND	0.017	0.038		ND	0.018	0.04	

Compound	Vanadium	Test Method: ICP-MS (EPA 1638)							Date 5/20/09			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 5/14/09	13.5	0.022	0.075		12.8	0.021	0.073		14.4	0.022	0.074	
Gas Oil - FCC - 5/20/09	0.26	0.022	0.074		0.264	0.022	0.075		0.252	0.022	0.074	
Gas Oil - TKN - 5/20/09	0.92	0.022	0.075		0.101	0.021	0.073		0.102	0.021	0.070	
Gas Oil - TKC - 5/20/09	0.272	0.022	0.075		0.268	0.022	0.074		0.277	0.021	0.072	

Compound	Mercury	Test Meth EPA 1631 (Cold Vapor Atomic Fluorescence Spectrometry)										
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit 5/14/09	ND	0.00046	0.00298		ND	0.00044	0.00284		ND	0.00046	0.00295	
Gas Oil - FCC - 5/20/09	ND	0.00046	0.00295		ND	0.00046	0.00297		ND	0.00044	0.00284	
Gas Oil - TKN - 5/20/09	ND	0.00091	0.00499		ND	0.00091	0.00481		ND	0.00088	0.00472	
Gas Oil - TKC - 5/20/09	ND	0.00047	0.00304		ND	0.00043	0.00278		ND	0.00045	0.00289	

Gas Samples - Metals

Compound	Mercury Date 6/24/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	MRL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	ND	0.001		0.1483	ND	ND	0.001		0.114	ND	ND	0.001		0.111	ND
Fuel Gas - V701	ND	0.001		0.1086	ND	ND	0.001		0.1088	ND	ND	0.001		0.1099	ND
Fuel Gas - V870	0.0147	0.001		0.1144	0.1285	0.0047	0.001		0.1141	0.0413	0.0024	0.001		0.1143	0.0210
Flare Gas - K1060/1070 (NY Flare)	ND	0.001		0.1106	ND	0.0033	0.001		0.1104	0.0299	ND	0.001		0.1101	ND
Flare Gas - K3950 (SY Flare)	ND	0.001		0.1130	ND	0.0004	0.001	J	0.1133	0.0035	ND	0.001		0.1133	ND

Compound	Cadmium Date 6/24/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	MRL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	ND	0.003		0.1483	ND	DNQ	0.003	J	0.1138	DNQ	ND	0.003		0.1110	ND
Fuel Gas - V701	0.0001	0.003		0.1086	0.0009	0.0022	0.003		0.1088	0.0202	ND	0.003		0.1099	ND
Fuel Gas - V870	ND	0.003		0.1144	ND	0.0072	0.003		0.1141	0.0631	ND	0.003		0.1143	ND
Flare Gas - K1060/1070 (NY Flare)	DNQ	0.003		0.1106	DNQ	0.0001	0.003	J	0.1104	0.0009	ND	0.003		0.1101	ND
Flare Gas - K3950 (SY Flare)	DNQ	0.003		0.1130	DNQ	ND	0.003		0.1133	ND	0.0022	0.003		0.1133	0.0194

Compound	Nickel Date 6/24/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	MRL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	0.161	0.015		0.1483	1.0856	0.005	0.015		0.1138	0.0439	0.012	0.015		0.1110	0.1081
Fuel Gas - V701	DNQ	0.015		0.1086	DNQ	DNQ	0.015		0.1088	DNQ	DNQ	0.015		0.1099	DNQ
Fuel Gas - V870	DNQ	0.015		0.1144	DNQ	DNQ	0.015		0.1141	DNQ	DNQ	0.015		0.1143	DNQ
Flare Gas - K1060/1070 (NY Flare)	DNQ	0.015		0.1106	DNQ	0.001	0.015		0.1104	0.0091	0.003	0.015		0.1101	0.0272
Flare Gas - K3950 (SY Flare)	0.012	0.015		0.1130	0.1062	DNQ	0.015		0.1133	DNQ	0.071	0.015		0.1133	0.6267

Compound	Selenium Date 6/24/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	MRL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	0.5	0.150	J	0.1483	3.3715	ND	0.150		0.1138	ND	ND	0.150		0.1110	ND
Fuel Gas - V701	ND	0.150		0.1086	ND	ND	0.150		0.1088	ND	ND	0.150		0.1099	ND
Fuel Gas - V870	ND	0.150		0.1144	ND	ND	0.150		0.1141	ND	ND	0.150		0.1143	ND
Flare Gas - K1060/1070 (NY Flare)	ND	0.150		0.1106	ND	ND	0.150		0.1104	ND	ND	0.150		0.1101	ND
Flare Gas - K3950 (SY Flare)	ND	0.150		0.1130	ND	ND	0.150		0.1133	ND	ND	0.150		0.1133	ND

Compound	Vanadium Date 6/24/09														
	Replicate 1					Replicate 2					Replicate 3				
Source	Result ug	MRL ug	Flag	Vol Gas Sampled dscm*	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm	Result ug	MRL ug	Flag	Vol Gas Sampled dscm	Conc. ug/dscm
Fuel Gas - V475-B	ND	0.075		0.1483	ND	0.012	0.075	J	0.114	0.1054	0.013	0.075	J	0.111	0.1171
Fuel Gas - V701	0.011	0.075	J	0.1086	0.1013	ND	0.075		0.1088	ND	0.011	0.075	J	0.1099	0.1001
Fuel Gas - V870	0.011	0.075	J	0.1144	0.0962	ND	0.075		0.1141	ND	ND	0.075		0.1143	ND
Flare Gas - K1060/1070 (NY Flare)	0.011	0.075	J	0.1106	0.0995	0.014	0.075	J	0.1104	0.1268	0.011	0.075	J	0.1101	0.0999
Flare Gas - K3950 (SY Flare)	0.011	0.075	J	0.1130	0.0973	ND	0.075		0.1133	ND	ND	0.075		0.1133	ND

Liquid HC and Gas Samples - Total Sulfur

Compound:	Sulfur	
Source	Total Sulfur	
	wt %	mol ppm*
Liquid HC Samples - 4/26/09		
Crude Oil - Crude Unit 5/14/09	1.13	
Gas Oil - FCC - 5/20/09	0.232	
Gas Oil - TKN - 5/20/09	1.66	
Gas Oil - TKC - 5/20/09	2.24	
Gas Samples - 6/24/09		
V475-B - 6/23/09		15.2
V701 - 6/23/09		32.6
V870 - 6/24/09		6.2
K1060/1070 (NY Flare) - 6/23/09		22,017.6
K3950 (SY Flare) - 6/24/09		483.8

Key:

RL: Reporting Limit
MDL: Method Detection Limit
J Flag: Estimated value. Analyte detected at a level less than the Reporting Limit, but greater than or equal to the Method Detection Limit
DNQ: Detected but Not Quantified. All gas samples were blank corrected and where blank value exceeded the measured value, DNQ was denoted.
ND: Not detected
dsl: dry standard liter
dscm: dry standard cubic meter at 29.92 " Hg, 68 Deg. F (760 mm Hg 20 Deg C)
ppbvd: parts per billion by volume on a dry basis
Conc: Concentration
* Limit of detection for analysis was 0.1 mol ppm. Convert to wt/wt ppm S by multiplying by factor of 2.

January 18, 2010

Richard Mitchell
Director, Planning and Building Services
City of Richmond
1401 Marina Way South
Richmond, CA 94804

Chevron Richmond Refinery
Conditional Use Permit Condition D2

Dear Mr. Mitchell:

This letter provides the test report for Six Element Sampling at Chevron's Richmond Refinery for the Third Quarter of 2009. This information is submitted pursuant to Condition D2 of Chevron's Conditional Use Permit, Number 1101974, for the Chevron Energy and Hydrogen Renewal Project.

Sampling was performed according to the protocol submitted to the City and BAAQMD in December 2008. The final set of analytical results for Third Quarter 2009 samples were received by Chevron from the analytical laboratories on January 4, 2010.

Please find attached ***Six Element Sampling Results Report for Quarter Ending September 30, 2009*** which summarizes the results for each sample analysis required by the D2 condition.

If you have any questions concerning this report, please contact Ms. Winnie Lieu at (510) 242-2742.

Sincerely,

Original Signed By Karen Graul

KMG
Tery Lizarraga

Attachment:
Six Element Sampling Results Report for Quarter Ending September 30, 2009

Bcc:
Robert Chamberlain, Richmond Renewal Project
Rolf Lindenhayn, Richmond Renewal Project
ETC (c/o Matt Diaz)

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Report for Quarter Ending: 9/30/2009

Liquid Samples - Metals

Compound: [illegible]	Test Method: [illegible]								Date: [illegible]			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	ND	0.002	0.014		ND	0.002	0.015		ND	0.002	0.014	
Gas Oil - FCC	ND	0.002	0.014		ND	0.002	0.015		ND	0.002	0.014	
Gas Oil - TKN	ND	0.002	0.014		ND	0.002	0.014		ND	0.002	0.014	
Gas Oil - TKC	ND	0.002	0.015		ND	0.002	0.015		ND	0.002	0.016	

Compound	Nickel	Test Method: ICP-MS (EPA 1638)							Date: [illegible]			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	4.88	0.010	0.047		5.54	0.011	0.242		5.78	0.010	0.231	
Gas Oil - FCC	ND	0.010	0.234		0.193	0.011	0.049		0.547	0.010	0.237	
Gas Oil - TKN	ND	0.011	0.241		ND	0.010	0.233		ND	0.010	0.228	
Gas Oil - TKC	6.70	0.011	0.252		6.99	0.011	0.249		7.10	0.012	0.263	

Compound	[illegible]	Test Method: ICP-MS (EPA 1638)							Date: [illegible]			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	0.123	0.017	0.038		0.463	0.017	0.039		0.546	0.017	0.037	
Gas Oil - FCC	ND	0.017	0.037		0.062	0.018	0.039		0.059	0.017	0.038	
Gas Oil - TKN	0.063	0.017	0.039		0.053	0.017	0.037		0.050	0.016	0.036	
Gas Oil - TKC	0.602	0.018	0.040		0.625	0.018	0.040		0.587	0.019	0.042	

Compound	Vanadium	Test Method: ICP-MS (EPA 1638)							Date: [illegible]			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	12.1	0.021	0.071		14.4	0.021	0.073		14.4	0.020	0.069	
Gas Oil - FCC	0.237	0.021	0.070		0.210	0.021	0.073		0.916	0.021	0.071	
Gas Oil - TKN	0.255	0.021	0.072		0.221	0.021	0.070		0.186	0.020	0.068	
Gas Oil - TKC	16.2	0.022	0.076		16.8	0.022	0.075		16.7	0.023	0.079	

Compound	Mercury	Test Method: EPA [illegible] (Cold Vapor Atomic Fluorescence Spectrometry)							Date: [illegible]			
	Replicate 1				Replicate 2				Replicate 3			
Source	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	11.5	0.00046	0.00295		ND	0.00047	0.00305		ND	0.00047	0.00305	
Gas Oil - FCC	ND	0.00039	0.00250		ND	0.00041	0.00264		ND	0.00042	0.00268	
Gas Oil - TKN	ND	0.00045	0.00290		ND	0.00043	0.00280		ND	0.00042	0.00273	
Gas Oil - TKC	ND	0.00047	0.00302		ND	0.00046	0.00299		ND	0.00049	0.00316	

Gas Samples - Metals

Compound: Mercury — Dates: 9/15/09-9/16/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	ND	0.001		0.1118	ND	0.008	0.001		0.1113	0.0719	ND	0.001		0.1119	ND
Fuel Gas - V701	0.0012	0.001		0.1117	0.0107	ND	0.001		0.1121	ND	ND	0.001		0.1115	ND
Fuel Gas - V870	0.0564	0.001		0.1132	0.4982	0.0102	0.001		0.1131	0.0903	0.0096	0.001		0.1126	0.0855
Flare Gas - K1060/1070 (NY Flare)	ND	0.001		0.1274	ND										
Flare Gas - K3950 (SY Flare)	ND	0.001		0.1558	ND										

Compound: Cadmium — Dates: 9/15/09-9/16/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	0.003	0.003		0.1118	0.0268	0.007	0.003		0.1113	0.0629	ND	0.003		0.1119	ND
Fuel Gas - V701	0.0040	0.003		0.1117	0.0358	0.0030	0.003		0.1121	0.0268	ND	0.003		0.1115	ND
Fuel Gas - V870	ND	0.003		0.1132	ND	ND	0.003		0.1131	ND	ND	0.003		0.1126	ND
Flare Gas - K1060/1070 (NY Flare)	0.0030	0.003		0.1274	0.0236										
Flare Gas - K3950 (SY Flare)	ND	0.003		0.1558	ND										

Compound: Nickel — Dates: 9/15/09-9/16/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	0.044	0.015		0.1118	0.3937	0.157	0.015		0.1113	1.4102	0.005	0.015		0.1119	0.0447
Fuel Gas - V701	0.061	0.015		0.1117	0.5463	0.05	0.015		0.1121	0.4459	DNQ	0.015		0.1115	DNQ
Fuel Gas - V870	DNQ	0.015		0.1132	DNQ	0.023	0.015		0.1131	0.2033	0.001	0.015		0.1126	0.0089
Flare Gas - K1060/1070 (NY Flare)	0.013	0.015		0.1274	0.1021										
Flare Gas - K3950 (SY Flare)	DNQ	0.015		0.1558	DNQ										

Compound: Selenium — Dates: 9/15/09-9/16/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	ND	0.150		0.1118	ND	ND	0.150		0.1113	ND	ND	0.150		0.1119	ND
Fuel Gas - V701	ND	0.150		0.1117	ND	ND	0.150		0.1121	ND	ND	0.150		0.1115	ND
Fuel Gas - V870	ND	0.150		0.1132	ND	ND	0.150		0.1131	ND	ND	0.150		0.1126	ND
Flare Gas - K1060/1070 (NY Flare)	ND	0.150		0.1274	ND										
Flare Gas - K3950 (SY Flare)	ND	0.150		0.1558	ND										

Compound: Vanadium — Dates: 9/15/09-9/16/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	ND	0.075		0.1118	ND	ND	0.075		0.1113	ND	ND	0.075		0.1119	ND
Fuel Gas - V701	ND	0.075		0.1117	ND	ND	0.075		0.1121	ND	ND	0.075		0.1115	ND
Fuel Gas - V870	ND	0.075		0.1132	ND	ND	0.075		0.1131	ND	ND	0.075		0.1126	ND
Flare Gas - K1060/1070 (NY Flare)	ND	0.075		0.1274	ND										
Flare Gas - K3950 (SY Flare)	ND	0.075		0.1558	ND										

Liquid HC and Gas Samples - Total Sulfur

Compound	Sulfur	
Source	Total Sulfur	
	wt %	mol ppm*
Liquid HC Samples Dates:7/13/09		
Crude Oil - Crude Unit	1.34	
Gas Oil - FCC	0.264	
Gas Oil - TKN	1.41	
Gas Oil - TKC	2.44	
Gas Samples Dates: 9/15/09-9/16/09		
Fuel Gas - V475-B		33.0
Fuel Gas - V701		39.5
Fuel Gas - V870		42.5
Flare Gas - K1060/1070 (NY Flare)		45,854
Flare Gas - K3950 (SY Flare)		20.5

Key:

RL: Reporting Limit
MDL: Method Detection Limit
MRL: Method Reporting Limit
J Flag: Estimated value. Analyte detected at a level less than the Reporting Limit, but greater than or equal to the Method Detection Limit
DNQ: Detected but Not Quantified. All gas samples were blank corrected and where blank value exceeded the measured value, DNQ was denoted.
ND: Not detected
dsl: dry standard liter
dscm: dry standard cubic meter at 29.92 " Hg, 68 Deg. F (760 mm Hg 20 Deg C)
ppbvd: parts per billion by volume on a dry basis
Conc: Concentration
* Limit of detection for analysis was 0.1 mol ppm. Convert to wt/wt ppm S by multiplying by factor of 2.

January 18, 2010

Richard Mitchell
Director, Planning and Building Services
City of Richmond
1401 Marina Way South
Richmond, CA 94804

Chevron Richmond Refinery
Conditional Use Permit Condition D2

Dear Mr. Mitchell:

This letter provides the test report for Six Element Sampling at Chevron's Richmond Refinery for the Fourth Quarter of 2009. This information is submitted pursuant to Condition D2 of Chevron's Conditional Use Permit, Number 1101974, for the Chevron Energy and Hydrogen Renewal Project.

Sampling was performed according to the protocol submitted to the City and BAAQMD in December 2008. The final set of analytical results for Fourth Quarter 2009 samples were received by Chevron from the analytical laboratories on January 15, 2010.

Please find attached ***Six Element Sampling Results Report for Quarter Ending December 31, 2009*** which summarizes the results for each sample analysis required by the D2 condition.

If you have any questions concerning this report, please contact Ms. Winnie Lieu at (510) 242-2742.

Sincerely,

Tery Lizarraga

Attachment:
Six Element Sampling Results Report for Quarter Ending December 31, 2009

Bcc:
Robert Chamberlain, Richmond Renewal Project
Rolf Lindenhayn, Richmond Renewal Project
ETC (c/o Matt Diaz)

Chevron Richmond Refinery
Conditional Use Permit Condition D2
Report for Quarter Ending: 12/31/09

Liquid Samples - Metals

Compound:	Cadmium		Test Method: ICP-MS (EPA 1638)						Date: 11/3/09 to 11/6/09			
Source	Replicate 1				Replicate 2				Replicate 3			
	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	ND	0.002	0.014		ND	0.002	0.015		ND	0.002	0.015	
Gas Oil - FCC	ND	0.002	0.015		ND	0.002	0.014		ND	0.002	0.014	
Gas Oil - TKN	ND	0.002	0.015		ND	0.002	0.015		ND	0.002	0.015	
Gas Oil - TKC	ND	0.002	0.014		ND	0.002	0.014		ND	0.002	0.015	

Compound:	Nickel		Test Method: ICP-MS (EPA 1638)						Date: 11/3/09 to 11/6/09			
Source	Replicate 1				Replicate 2				Replicate 3			
	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	4.63	0.011	0.048		2.00	0.011	0.050		4.89	0.011	0.050	
Gas Oil - FCC	0.416	0.011	0.049		0.435	0.010	0.046		0.407	0.010	0.048	
Gas Oil - TKN	0.079	0.011	0.050		0.080	0.011	0.049		0.080	0.011	0.049	
Gas Oil - TKC	0.362	0.010	0.047		0.360	0.010	0.047		0.360	0.011	0.049	

Compound:	Selenium		Test Method: ICP-MS (EPA 1638)						Date: 11/3/09 to 11/6/09			
Source	Replicate 1				Replicate 2				Replicate 3			
	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	ND	0.017	0.048		ND	0.018	0.050		ND	0.018	0.050	
Gas Oil - FCC	0.075	0.018	0.039		0.095	0.017	0.037		0.049	0.017	0.038	
Gas Oil - TKN	0.233	0.018	0.040		0.243	0.018	0.039		0.246	0.018	0.039	
Gas Oil - TKC	0.110	0.017	0.038		0.112	0.017	0.037		0.079	0.018	0.039	

Compound:	Vanadium		Test Method: ICP-MS (EPA 1638)						Date: 11/3/09 to 11/6/09			
Source	Replicate 1				Replicate 2				Replicate 3			
	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	11.5	0.021	0.072		4.61	0.022	0.075		13.0	0.022	0.075	
Gas Oil - FCC	0.441	0.022	0.074		0.448	0.020	0.070		0.435	0.021	0.072	
Gas Oil - TKN	0.139	0.022	0.075		0.134	0.022	0.074		0.138	0.022	0.074	
Gas Oil - TKC	0.375	0.021	0.071		0.377	0.020	0.070		0.376	0.021	0.073	

Compound:	Mercury		Test Method: EPA 1631 (Cold Vapor Atomic Fluorescence Spectrometry)						Date: 11/3/09 to 11/6/09			
Source	Replicate 1				Replicate 2				Replicate 3			
	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag	Result mg/kg	MDL mg/kg	RL mg/kg	Flag
Crude Oil - Crude Unit	ND	0.00046	0.00297		ND	0.00046	0.00294		ND	0.00045	0.00292	
Gas Oil - FCC	ND	0.00044	0.00287		ND	0.00045	0.00289		ND	0.00046	0.00294	
Gas Oil - TKN	ND	0.00044	0.00286		ND	0.00044	0.00287		ND	0.00045	0.00293	
Gas Oil - TKC	ND	0.00045	0.00294		ND	0.00047	0.00303		ND	0.00044	0.00285	

Gas Samples - Metals

Compound: Mercury — Dates: 11/10/09 - 11/11/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	0.3875	0.12		0.1146	3.3824	ND	0.001		0.1142	ND	ND	0.001		0.1144	ND
Fuel Gas - V701	0.0004	0.002		0.1197	0.0033	ND	0.001		0.1153	ND	0.0831	0.001		0.1150	0.7226
Fuel Gas - V870	0.0066	0.002		0.1185	0.0554	0.0096	0.001		0.1178	0.0814	0.0103	0.001		0.1169	0.0881
Flare Gas - K1060/1070 (NY Flare)	ND	0.002		0.1275	ND										
Flare Gas - K3950 (SY Flare)	0.0081	0.002		0.1218	0.0665										

Compound: Cadmium — Dates: 11/10/09 - 11/11/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	DNQ	0.003	J	0.1146	DNQ	DNQ	0.003	J	0.1142	DNQ	DNQ	0.003	J	0.1144	DNQ
Fuel Gas - V701	DNQ	0.003		0.1197	DNQ	DNQ	0.003	J	0.1153	DNQ	DNQ	0.003	J	0.1150	DNQ
Fuel Gas - V870	DNQ	0.003	J	0.1185	DNQ	ND	0.003		0.1178	ND	DNQ	0.003	J	0.1169	DNQ
Flare Gas - K1060/1070 (NY Flare)	DNQ	0.003	J	0.1275	DNQ										
Flare Gas - K3950 (SY Flare)	DNQ	0.003	J	0.1218	DNQ										

Compound: [illegible] — Dates: [illegible]

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	DNQ	0.015		0.1146	DNQ	DNQ	0.015		0.1142	DNQ	DNQ	0.015		0.1144	DNQ
Fuel Gas - V701	0.0240	0.015		0.1197	0.2005	DNQ	0.015		0.1153	DNQ	DNQ	0.015		0.1150	DNQ
Fuel Gas - V870	DNQ	0.015		0.1185	DNQ	DNQ	0.015		0.1178	DNQ	DNQ	0.015		0.1169	DNQ
Flare Gas - K1060/1070 (NY Flare)	DNQ	0.015		0.1275	DNQ										
Flare Gas - K3950 (SY Flare)	DNQ	0.015		0.1218	DNQ										

Compound: Selenium — Dates: 11/10/09 - 11/11/09

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	ND	0.150		0.1146	ND	ND	0.150		0.1142	ND	ND	0.150		0.1144	ND
Fuel Gas - V701	ND	0.150		0.1197	ND	ND	0.150		0.1153	ND	ND	0.150		0.1150	ND
Fuel Gas - V870	ND	0.150		0.1185	ND	ND	0.150		0.1178	ND	ND	0.150		0.1169	ND
Flare Gas - K1060/1070 (NY Flare)	ND	0.150		0.1275	ND										
Flare Gas - K3950 (SY Flare)	ND	0.150		0.1218	ND										

Compound: [illegible] — Dates: [illegible]

Source	Replicate 1 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 2 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm	Replicate 3 Result µg	MRL µg	Flag	Vol Gas Sampled dscm	Conc. µg/dscm
Fuel Gas - V475-B	ND	0.075		0.1146	ND	ND	0.075		0.1142	ND	ND	0.075		0.1144	ND
Fuel Gas - V701	ND	0.075		0.1197	ND	ND	0.075		0.1153	ND	ND	0.075		0.1150	ND
Fuel Gas - V870	ND	0.075		0.1185	ND	ND	0.075		0.1178	ND	ND	0.075		0.1169	ND
Flare Gas - K1060/1070 (NY Flare)	ND	0.075		0.1275	ND										
Flare Gas - K3950 (SY Flare)	ND	0.075		0.1218	ND										

Liquid HC and Gas Samples - Total Sulfur

Compound:	Sulfur	
Source	Total Sulfur	
	wt %	mol ppm*
Liquid HC Samples Dates: 12/2/09-12/13/09		
Crude Oil - Crude Unit	1.94	
Gas Oil - FCC	0.295	
Gas Oil - TKN	1.60	
Gas Oil - TKC	0.30	
Gas Samples Dates: 11/10/09-11/12/09		
Fuel Gas - V475-B		33.5
Fuel Gas - V701		41.6
Fuel Gas - V870		54.1
Flare Gas - K1060/1070 (NY Flare)		24,593
Flare Gas - K3950 (SY Flare)		23,714

Key:

RL: Reporting Limit
MDL: Method Detection Limit
MRL: Method Reporting Limit
J Flag: Estimated value. Analyte detected at a level less than the Reporting Limit, but greater than or equal to the Method Detection Limit
DNQ: Detected but Not Quantified. All gas samples were blank corrected and where blank value exceeded the measured value, DNQ was denoted.
ND: Not detected
dsl: dry standard liter
dscm: dry standard cubic meter at 29.92 " Hg, 68 Deg. F (760 mm Hg 20 Deg C)
ppbvd: parts per billion by volume on a dry basis
Conc: Concentration
* Limit of detection for analysis was 0.1 mol ppm. Convert to wt/wt ppm S by multiplying by factor of 2.